**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Develop A Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	Rulemaking 14-07-002 (Filed July 10, 2014)

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) COMMENTS ON PARTY PROPOSALS AND STAFF PAPERS

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I. INTRODUCTION

In accordance with the June 4 Ruling of Administrative Law Judge Simon, Pacific Gas and Electric Company (PG&E) files these comments on party proposals and staff papers concerning Net Energy Metering (NEM) reform. The filings showed a strong consensus on the need for change among ratepayer advocates (ORA and TURN), one environmental group (NRDC), and the three investor-owned utilities. Similarly, Energy Division staff studies showed substantial cost shifting with the current NEM design, even after residential rate reform, and the opportunity for solar customers to continue to achieve substantial savings even with NEM reform. PG&E believes that this broad consensus portends well for a rational, fact-based outcome that supports a sustainable, unconstrained future for solar and other renewable distributed energy technologies.

While these reform-oriented parties' specific proposals for reform varied somewhat, all show promise in ensuring continued growth of the solar market while reducing the rate impacts of the subsidies provided under the current NEM design. Proposals for a demand charge or installed capacity charge were offered by SDG&E, SCE, ORA, NRDC, and PG&E. Feed-in tariff proposals were offered by TURN and SDG&E. Almost all parties proposing change suggested reducing export compensation, which would decouple the rate at which exports are compensated from the full retail rate. Energy Division in its illustrative NEM reform proposal highlighted two mechanisms by which export compensation could be reduced.

In contrast to the reform-oriented parties, several parties (CalSEIA, SEIA/Vote Solar, TASC and Sierra Club) proposed to maintain the status quo by extending the current NEM program design, with a slight decrease in the export credit at some unspecified future time. The "Status Quo" parties argued that there is no rate impact associated with the current NEM tariff, and that, even if there was, any change would cause a "train wreck" for the solar industry.

These claims are simply at odds with the facts. As the unmodified Public Tool demonstrates, the current NEM tariff results in very large rate impacts today and in the future, with estimates ranging from $3.6 to $5.0 billion dollars per year by 2025 shown in the bookend cases in the Public Tool, to $6.3 billion per year statewide using the base case solar price and the low avoided cost. PG&E's independent scenario showed an even higher cost shift of $7.2 billion per year. As discussed in more detail below, the total cumulative cost shift if the Commission keeps the existing NEM program for 2017-2025 and grandfathers all these customers for 20 years, could exceed $100 billion. This is a huge and unnecessary cost-shift; reasonable reform can reduce the impact dramatically and still allow solar to thrive.

In order to justify their claim that there is no cost shifting associated with the current NEM tariff, the Status Quo parties had to resort to heavily modifying many critical aspects of the Public Tool including the avoided costs calculated by Energy Division and E3. Among many other changes to the standard cost benefit analysis, they inflated the value of energy, distorted the RPS avoided costs, and claimed an unreasonably high value for avoided transmission and distribution capacity costs. They also added huge values for claimed "societal" costs avoided by net metering. It is inappropriate for the Commission to use the societal cost test. However, if it chooses to consider it, the Commission should certainly not use values proposed by Sierra Club, and relied on by the other "Status Quo" parties.

Similarly, the Status Quo parties claimed that any change to NEM will destroy the solar industry. These alarmist claims are simply not true. Even after rate reform and NEM reform, there will be plenty of room for customers to save money by installing solar, even at today's prices, as solar vendors have been telling their investors. Moreover, while solar component costs have fallen dramatically over the last few years, much of the potential savings has not been realized by participating customers in California in the form of lower prices, resulting in far higher profit margins for solar vendors here than in other states. PG&E firmly believes and desires that solar vendors will continue to have a bright future, and that they will remain active and productive in California. In addition, PG&E feels strongly that establishing a reasonable timeline for revisiting NEM design – PG&E proposes three years – is critical to ensuring that the legislative requirements of AB 327 are met in the long run.

As demonstrated through the Public Tool, failure to reform NEM will cause rates for California utility customers to escalate significantly, even though solar is already cost competitive without such subsidies. Moreover, these higher costs are not just borne by high usage residential customers or business customers; even low usage residential customers and CARE customers must pick up costs resulting when customers install solar under current NEM design. These costs are becoming enormous, and will soon become even larger than the subsidy to CARE customers. Change in NEM design is essential and now is the right time to make that change.

The reform-oriented proposals show a promising path forward to a sustainable and unconstrained future for solar, storage and other renewable DG technologies, where utility solar customers continue to save on their energy bills and help fund the infrastructure needed to enable their technologies. Reform parties have proposed a variety of reasonable, predictable and stepwise approaches to change that can allow the solar industry to continue to thrive even in the face of change.

PG&E's proposal contains a demand charge to recover at least some of the cost of the distribution system relied on by solar customers. PG&E believes a demand charge is the appropriate structure to recover these costs because it better captures the utility's cost to serve customers and customers can modify their demand to increase the savings they will enjoy from their renewable generation. PG&E also recommends compensation for exported energy that is closer to (but still above) the value of those exports to other customers. Should the CPUC adopt PG&E's proposal, the structure will be in place to ensure a thriving market for renewable customer generation, while continuing the process of reducing the impact on rates that was started in the residential rate reform proceeding.

PG&E urges the CPUC to act now to establish an appropriate long-term, sustainable solution that supports California's distributed energy future. While PG&E's proposal does not constitute the end state, as further review in a few years will be appropriate, delaying implementation of significant reform of the NEM program will squander this opportunity to move toward a sustainable solution and is contrary to clear Legislative direction.

II. DISCUSSION OF THE PROPOSALS FOR REGULAR NEM

A. Overview: NEM Needs To Be Reformed

On August 3, 2015, sixteen parties filed proposals in this proceeding.[1/] Many parties recognized that the residential rate reform only partially addressed the need for NEM reform, and that a significant cost shift remains that must be addressed before any successor tariff can be considered sustainable and able to accommodate unlimited renewable customer generation. The sixteen proposals can be grouped into four categories:

1. Pro-Reform: The majority of parties submitting proposals for successor tariffs (PG&E, SCE, SDG&E, ORA, TURN, and NRDC) clearly recognize that reform is necessary to address rate impacts and to design the successor tariff in such a way as to balance interests of all customers (as the Legislature directed). Energy Division also

1/ These were filed by Southern California Edison (SCE), the Natural Resources Defense Council (NRDC), the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), San Diego Gas and Electric Company (SDG&E), California Farm Bureau Federation (CFBF), Federal Executive Agencies (FEA), Solar Energy Industries Association and Vote Solar (SEIA/Vote Solar), the California Solar Industries Association (CalSEIA), the Alliance For Solar Choice (TASC), California Environmental Justice Alliance (CEJA), Everyday Energy, Grid Alternatives, Interstate Renewable Energy Council (IREC), and Californians for Renewable Energy (CARE).

submitted illustrative NEM reform scenarios in its whitepaper.[2/] PG&E supports many elements of the pro-reform parties' proposals, and believes that consensus could be reached among these parties on terms for sustainable reform.

2. Status Quo: Some parties (SEIA/Vote Solar, TASC, CalSEIA, and the Sierra Club), argued that no NEM reform is necessary. Three of these four represent vendors who sell solar equipment to utility customers and, as such, have a strong economic interest in maintaining the lucrative incentives under the current NEM program; the other party (Sierra Club) states that further reform will be accomplished if customers installing renewable generation in the future take service on Time-of-Use rates. With respect to public purpose program charges (PPP), two of the Status Quo parties suggested that someday, solar customers might pay public purpose program charges (PPP), but not anytime soon. PG&E strongly disagrees with these parties' contention that no change to the current NEM tariff is warranted at this time.
3. Special Interest: Two parties (CFBF and FEA) focused on single-issue solutions for their constituents. CFBF seeks continuation of account aggregation for agricultural customers and FEA wants to ensure that installations larger than 1 MW are permitted under the successor tariff. PG&E supports both of these positions, with appropriate protection for ratepayers. One other special interest party (CARE) filed a proposal on July 23, 2015, suggesting that it would be more appropriate to restrict customers installing renewable generation to a power purchase agreement with their utility, based on PURPA.
4. Disadvantaged Communities: Four parties (Grid Alternatives, IREC, CEJA, and Everyday Energy) submitted proposals that address the Legislative direction to ensure growth in disadvantaged communities, but did not propose a tariff that met the other

2/ The Energy Division White Paper is Attachment 1 to the June 4 Ruling ("White Paper.") See pages 1-31 to 1-43 for the discussion of alternate export compensation scenarios.

legislative requirements. Several parties (PG&E, SCE, SDG&E, and SEIA/Vote Solar) submitted specific proposals for disadvantaged communities in addition to their standard successor tariff proposals while others (CalSEIA, ORA, TURN, Everyday Energy) supported (or could support with some changes) Energy Division and/or IREC's proposals. Additionally, a few parties (NRDC, CA Farm Bureau) did not submit a specific proposal for disadvantaged communities with some (Sierra Club, TASC) stating they look forward to commenting on others' proposals.

PG&E's proposal falls within the group that recognizes the need for reform. Our proposal includes a time-of-use (TOU) residential rate with a small demand charge and a similar rate for commercial customers who are not on a demand rate. Nonresidential customers who are on a rate with a demand charge will continue to receive service under their applicable rate. Introduction of a demand charge for all NEM customers will ensure that at a portion of the distribution capacity costs of service are recovered from those customers. In addition to demand charges, all customers on the NEM successor tariff would receive credit for their exported energy at a value closer to (but still in excess of) the value of those exports to other customers. These changes will reduce the financial impact solar installations cause to be borne by customers who do not install solar. PG&E has focused its proposal on establishing the appropriate tariff structure with only modest reforms in the near-term. PG&E has also proposed that, in the long-term, the CPUC continue to implement reforms to align the price and value of energy delivered to the utility or its customers under the NEM successor tariff. To this end, PG&E proposed that the CPUC revisit the tariff in three years or less.

PG&E supports the many other parties who proposed reasonable approaches to reducing the solar incentives and applauds the general consensus among the broad interests supporting further reform. For example, SDG&E, NRDC and PG&E all propose a demand charge structure for NEM. PG&E believes rate structures that include demand charges better align rates with the costs that customers impose on the system. As a result these structures promote efficient use of the grid by encouraging customers to reduce their charges by managing their maximum load.

Moreover, appropriately set demand charges will unlock the potential for innovation (including energy storage) to best respond these incentives and allow customers to better manage their energy bills.

By comparison, some Reform parties (i.e., ORA and SCE) have recommended use of an installed capacity charge. California IOUs have used this mechanism for decades for standby charges. It is a far superior approach than volumetric rates for recovering capacity costs or other costs not driven by volumetric energy usage. Moreover, it is simple to administer and is readily understood by customers. While recognizing the benefits to this approach, PG&E believes the demand charge structure better enables a distributed energy future, gives customers the ability to manage this portion of their bill, and sends customers the price signals to better align their energy use with the utility cost of service. In fact, PG&E's demand charge proposal is not intended to be limited to NEM customers, but would also be open to all other customers on a voluntary basis. While only recovering a portion of distribution costs through demand charges, this revenue neutral rate design structure is simply charging customers based on how they use the grid.

Most Reform parties included reduction to export compensation as a component of their proposal, which PG&E recognizes and supports. The current practice of crediting exports at the full retail rate bears no relationship to the actual value of the generation exported to the grid and paid for by other customers.

Most parties recognize the value of using correctly designed time of use (TOU) rates to present customers with important information about when their renewable generation is most valuable and when their usage could be modified to the greatest benefit of all customers.

TURN proposes a feed in tariff for all generation, where customers would pay for their gross usage as they do now. PG&E recognizes the transparency of a feed-in tariff, and TURN's proposal to credit customers' bills (rather than direct payment for the generation) could address the tax implications of a feed in tariff.

Finally, all Reform parties (and the Energy Division) recognized that the appropriate metrics for evaluating different proposals are (at least) the participant cost test (PCT) and the ratepayer impact measure (RIM). The former evaluates the impact of a proposal on the value proposition for customers who choose to install renewable generation and the latter measures the rate impact of those choices on others. If both the PCT and RIM tests result in a benefit-cost ratio close to one, that represents the balance of interests best. However, PG&E notes that customers may require a PCT slightly higher than 1.0 to reflect a proposal where customers can achieve savings from their choice to install renewable generation. It is most important, as is explained below, that the CPUC not choose the total resource cost (TRC) or societal cost test (SCT) to evaluate proposals. The legislature could not possibly have intended these two metrics be used to evaluate NEM successor tariff proposals because they provide no information on which rate proposal should be adopted. All rate impacts are ignored under both the TRC and SCT tests, subsidies from non-solar to solar customers (no matter how large) are as simply treated as an income transfer from one set of customer to another, resulting in no change to the TRC or SCT values.

The CPUC can assess whether NEM reform is needed by first comparing the six bookend cases parties were instructed to provide, using their proposals and the default input assumptions in the Public Tool. PG&E assumed (and most parties have confirmed) that the "Status Quo" parties' bookend cases can be found from the six bookend cases run using the default rates in the Public Tool. As TASC stated,[3/] the tables provided by the Energy Division (which were extracted from such a run) represent their bookend cases. Results for the low and high two tier bookends are reproduced in Table 1 and Table 2, below, for discussion purposes. Results for bookends assuming the other two rate structures are very similar to the results presented in Table 1 and Table 2.

3/ TASC, page 30.

Table 1: Low DG Value Two Tier Bookend[4/]

Party	2017-2025 MW installed	PCT	RIM	TRC	Average Cost Shift per kWh (All Generation)	Annual Cost Shift in 2025 ($B)	NPV of RIM as % of RRQ
PG&E	5,389	1.14	0.36	0.45	($0.15)	($1.35)	2.71%
SDG&E	4,863	1.05	0.42	0.46	($0.12)	($0.97)	1.99%
SCE	4,890	1.01	0.43	0.46	($0.12)	($0.98)	1.89%
ORA - ($10/kW)	8,262	1.14	0.32	0.44	($0.17)	($2.34)	4.63%
TURN ($0.10 DGA)	4,059	1.02	0.5	0.57	($0.13)	($0.88)	1.73%
NRDC	10,628	1.36	0.25	0.41	($0.22)	($3.89)	7.52%
SEIA-VoteSolar	11,985	1.46	0.22	0.39	($0.25)	($4.99)	9.54%
TASC	11,985	1.46	0.22	0.39	($0.25)	($4.99)	9.54%
CalSEIA	11,985	1.46	0.22	0.39	($0.25)	($4.99)	9.54%
Sierra Club	11,985	1.46	0.22	0.39	($0.25)	($4.99)	9.54%
FEA	11,985	1.46	0.22	0.39	($0.25)	($4.99)	9.54%

Table 2: High DG Value Two Tier Bookend

Party	2017-2025 MW installed	PCT	RIM	TRC	Average Cost Shift per kWh (All Generation)	Annual Cost Shift in 2025 ($B)	NPV of RIM as % of RRQ
PG&E	11,327	1.88	0.68	1.14	($0.06)	($1.13)	2.31%
SDG&E	5,083	2.15	0.63	1.2	($0.09)	($0.76)	1.42%
SCE	6,789	1.91	0.71	1.17	($0.06)	($0.68)	1.29%
ORA - ($10/kW)	15,255	1.94	0.6	1.11	($0.09)	($2.29)	4.27%
TURN ($0.10 DGA)	16,505	2.26	0.46	1.05	($0.14)	($3.85)	7.77%
NRDC	15,724	2.37	0.51	1.09	($0.13)	($3.40)	6.41%
SEIA-VoteSolar	16,047	2.51	0.47	1.07	($0.14)	($3.74)	7.53%
TASC	16,047	2.51	0.47	1.07	($0.14)	($3.74)	7.53%
CalSEIA	16,047	2.51	0.47	1.07	($0.14)	($3.74)	7.53%
Sierra Club	16,047	2.51	0.47	1.07	($0.14)	($3.74)	7.53%
FEA	16,047	2.51	0.47	1.07	($0.14)	($3.74)	7.53%

As Table 1 and Table 2 illustrate, for each of the six bookends and for every party's proposal, the results are similar: The Participant Cost Test (PCT) is above 1.0 (meaning that participating customers are better off); the Ratepayer Impact Measure (RIM) test is below 1.0 (meaning the revenue losses and program and other costs of NEM are larger than the avoided costs, resulting in higher rates); and the Total Resource Cost (TRC) test is below 1.0 in Table 1 and several other scenarios that follow. The only scenario with a TRC above 1.0 is Table 2 above. That is the "High DG value" scenario. The TRC figure in Table 1 indicates that customer renewable generation is less cost-effective than alternative means of meeting electricity

4/ All results tables show the ORA's endpoint scenario ($10/kW installed capacity fee). Given the proposed size of each installed capacity fee "tranche" and the rate of adoption predicted by the tool under those proposals, PG&E believes ORA's end state would be reached extremely quickly, making it the most representative scenario. These figures and similar figures in the tables that follow are statewide figures for all three investor-owned utilities.

needs of our customers, if one assumes the low avoided cost value and the high PV price in that scenario. PG&E notes, though, that the decision to support such generation as a matter of policy was settled in AB 327 and is not relevant in this tariff design process.[5/] As is discussed in detail below, the TRC test is irrelevant to the rate-making issues involved here.

Table 3, below, shows the results for all six bookends for the Status Quo proposals. These are simply the results from the six Energy Division Scenarios, but they represent the solar party proposals evaluated using the six bookend assumptions.

Table 3: Energy Division Bookend Scenarios – Evaluation of "Status Quo" Proposals

Scenario	2017-2025 MW installed	PCT	RIM	TRC	Average Cost Shift per kWh (All Generation)	Annual Cost Shift in 2025 ($B)	NPV of RIM as % of RRQ
ED Staff_DGValue High_Two Tiers	16,047	2.51	0.47	1.07	($0.14)	($3.74)	7.53%
ED Staff_DGValue Low_Two Tiers	11,985	1.46	0.22	0.39	($0.25)	($4.99)	9.54%
ED Staff_DGValue High_TOU 2to8	14,707	2.66	0.46	1.11	($0.15)	($3.67)	7.32%
ED Staff_DGValue Low_TOU 2to8	11,771	1.54	0.21	0.39	($0.26)	($5.09)	9.97%
ED Staff_DGValue High_TOU 4to8	15,622	2.52	0.47	1.09	($0.14)	($3.64)	7.30%
ED Staff_DGValue Low_TOU 4to8	12,098	1.45	0.22	0.39	($0.25)	($5.03)	9.67%

The bookends are designed to establish reasonable bounds for the likely future, with input assumptions that are lower than expected and higher than expected. Therefore one would assume that the future outcome of any given proposal would fall between the lowest outcomes and highest outcomes of the six book-ends. It is clear from the six scenario evaluations of the solar proposal in Table 3 that the Status Quo parties' recommended approach for NEM does not meet any reasonable interpretation of the requirements under AB 327. The participant and solar vendor are always better off; indicating that market growth is assured (other things being equal). On the other hand, there is obviously a continuing and significant rate impact for customers (as the RIM values are well below 1.0). The rate impact shown in these tables is persistent and reaches alarming levels by 2025, when the annual rate impact ranges from $3.6 to $5.0 billion

5/ If the CPUC were considering *whether* to support customer generation, then the TRC test would be appropriate as a metric to compare proposals.

statewide. Over the assessed timeline (2017-2050), this cost shift is between 7.3% and 10% of utility revenue requirements. This actual impact on rates is far more severe, with PG&E's residential rates increasing by about 15% in either bookend scenario in 2025 due to NEM related cost shifting.[6/] The total cumulative cost shift if the Commission keeps existing NEM for 2017-2025 and grandfathers all these customers for 20 years thereafter, could exceed $100 billion.[7/]

The advocates of "no reform," i.e., the Status Quo parties, provide limited analysis to support their claim of no cost shift. As discussed in more detail below, this analysis is based on deeply flawed assumptions, inconsistent reasoning, and recommendations for measurement that are contrary to Legislative intent and do not follow the CPUC's own measurement rules. For example, the Status Quo parties make many modifications to the Public Tool's inputs and basic functionality in order to justify their conclusion that there is no rate impact. It is important to note that, despite the fact that many parties (including PG&E) disagreed with the values and/or mechanics of the Public Tool, the Status Quo parties alone made drastic modifications to the tool in an attempt to justify maintenance of the status quo.

While the Status Quo parties appear to support the CPUC's Standard Practice Manual tests; they make major changes to the TRC and Societal Cost Test (SCT) that cannot be justified. The Status Quo parties caution the CPUC against assuming the outcome of other proceedings when evaluating proposals, yet they rely on a unique interpretation of California's likely future climate change measures to achieve an inflated RPS avoided cost.

PG&E notes that the Energy Division's bookend cases, while valuable for comparison purposes, do not reflect the most likely future state. The Low cases assume a low "avoided cost" value of DG, but combine it with a very high price for customers installing solar. The scenario

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6/ Taken from the "Detailed Rate Outputs" table on the results tab of the Public Tool. This rate increase is significantly higher than the "NPV of RIM % of RRQ" metric because the latter includes many years (2026-2050) where no additional adoption is assumed to occur, while revenue requirements increase substantially.

7/ Five billion dollars per year for 20 years would add up to $100 billion in nominal dollars.

input assumptions temper the cost-shift impact, as adoption is relatively low but the cost-shift per MW installed is very high. On the other hand, the High cases assume a high "avoided cost" value of DG, but combine that with the "low price" scenario for solar. This, too, results in a tempered cost-shift, as adoption is relatively high, but the cost-shift per MW installed is relatively low. PG&E believes that given the cost trajectory of rooftop solar the "low price" scenario is most likely to prevail. PG&E also believes that due to the expected excess supply of mid-day energy in certain months under 33% to 50% RPS mandates (in which a sizable portion of the RPS obligation is met by solar), the avoided cost value of stand-alone rooftop solar is likely to be low.

PG&E compared all of the proposals by creating a comparison scenario based on input assumption options provided in the Public Tool, but moving away from the six bookend scenarios. This new comparison scenario started with the input assumptions in the "Low Two Tier" bookend, kept the low avoided cost assumption, but substituted the base case PV cost input assumption. PG&E believes these assumptions represent a highly defensible and likely future scenario.

We hope this analysis can facilitate the comparison of parties' proposals by putting all proposals on the same level by using input assumptions that parties can reasonably expect will occur. The results, in Table 4 below, create the ability to discuss the extent to which proposals can or will meet legislative requirements, at least at a high level, and at least in relationship to each other. This should provide the CPUC with an ability to generally determine what proposals will more likely work and what proposals will more likely fail to satisfy Legislative criteria.

Table 4: Comparison of Proposals with Base Case Solar Price and Low Avoided Cost Assumptions

Party	2017-2025 MW installed	PCT	RIM	TRC	Average Cost Shift per kWh (All Generation)	Annual Cost Shift in 2025 ($B)	NPV of RIM as % of RRQ
PG&E	8,726	1.44	0.37	0.51	($0.14)	($2.03)	3.81%
SDG&E	6,548	1.41	0.41	0.53	($0.12)	($1.31)	2.58%
SCE	6,793	1.33	0.42	0.53	($0.11)	($1.24)	2.51%
ORA - ($10/kW)	13,451	1.28	0.31	0.52	($0.16)	($3.58)	9.04%
TURN ($0.10 DGA)	9,946	1.2	0.52	0.65	($0.12)	($1.99)	4.02%
NRDC	14,824	1.8	0.22	0.43	($0.22)	($5.43)	10.36%
SEIA-VoteSolar	15,842	1.94	0.19	0.42	($0.24)	($6.33)	12.42%
TASC	15,842	1.94	0.19	0.42	($0.24)	($6.33)	12.42%
CalSEIA	15,842	1.94	0.19	0.42	($0.24)	($6.33)	12.42%
Sierra Club	15,842	1.94	0.19	0.42	($0.24)	($6.33)	12.42%
FEA	15,842	1.94	0.19	0.42	($0.24)	($6.33)	12.42%

In this analysis, the two camps identified earlier have dramatically different performance under all metrics. The Reform-minded parties generally have proposals with lower PCT, higher RIM, lower rate impacts and smaller percentage of revenue requirements required to support their proposal. While the Reform-minded parties propose a variety of different successor tariff structures, the results for all of them show progress in reducing cost shifts while continuing solar adoption.[8/] This means, of course, that more than one tariff proposal can help move toward meeting the legislative goals of AB 327.

However, the "Status Quo" proposals do not meet the legislative goals.[9/] The MW installed are significantly higher, as is the PCT. The flip side is that the RIM is much smaller for the Status Quo parties, and the cost shift is much larger. The annual rate impact in 2025, over $6.3 billion per year, is 3 to 5 *times* the impact of some of the reform-minded proposals.

8/ All five "Status Quo" parties have exactly the same results because their proposal is to leave NEM unchanged once rate reform is implemented. The only difference is that some parties support eventually reducing the export compensation by the non-bypassable charges (NBCs). PG&E did not model this due to insufficient detail on timing and size of this change and an expectation that the impact is negligible.

9/ All five "Status Quo" parties have exactly the same results because their proposal is to leave NEM unchanged once rate reform is implemented. The only difference is that some parties support eventually reducing the export compensation by the non-bypassable charges (NBCs). PG&E did not model this due to insufficient detail on timing and size of this change and an expectation that the impact is negligible.

In addition, PG&E also examines the parties' proposals using the input assumptions in PG&E's "Independent Scenario."[10/] Under PG&E's Independent Scenario, the results for the status quo proposal are even more startling, with a statewide cost shift of over $7.2 billion per year. According to the results of the Public Tool, PG&E's residential rates would increase by about 30% in 2025 relative to a baseline with no such cost shift.[11/] This consequence is unacceptable to PG&E, and should be unacceptable to the CPUC, the Legislature, and the people of California.

Table 5: Comparison of Proposals with PG&E Independent Scenario

Scenario	2017-2025 MW installed	PCT	RIM	TRC	Average Cost Shift per kWh (All Generation)	Annual Cost Shift in 2025 ($B)	NPV of RIM as % of RRQ
PG&E	13,679	2.12	0.4	0.68	($0.11)	($2.50)	5.0%
SDG&E	7,538	2.21	0.47	0.82	($0.10)	($1.25)	2.55%
SCE	9,373	2.06	0.49	0.79	($0.09)	($1.40)	2.82%
ORA - ($10/kW)	18,042	2.24	0.29	0.62	($0.16)	($4.80)	9.18%
TURN	16,083	1.74	0.33	0.63	($0.13)	($3.48)	7.29%
NRDC	18,339	2.89	0.24	0.6	($0.20)	($6.10)	12.12%
SEIA-VoteSolar	18,843	3.09	0.21	0.59	($0.23)	($7.21)	13.88%
TASC	18,843	3.09	0.21	0.59	($0.23)	($7.21)	13.88%
CalSEIA	18,843	3.09	0.21	0.59	($0.23)	($7.21)	13.88%
Sierra Club	18,843	3.09	0.21	0.59	($0.23)	($7.21)	13.88%
FEA	18,843	3.09	0.21	0.59	($0.23)	($7.21)	13.88%

Under any reasonable method of evaluation, including the bookend cases, the more probable figures above, and PG&E's Independent Scenario, the cost shift is $3.6 to $7.2 billion per year if the CPUC fails to implement reform. NEM must be reformed.

10/ The inputs used for PG&E's Independent Scenario can be found in Appendix A of PG&E's Proposal.

11/ Taken from the "Detailed Rate Outputs" table on the results tab of the Public Tool. This rate increase is significantly higher than the "NPV of RIM % of RRQ" metric because the latter includes many years (2026-2050) where no additional adoption is assumed to occur, while revenue requirements increase substantially

B. Metrics Proposed For Evaluating The Statutory Criteria

In this section, PG&E discusses the appropriate metrics to be used to evaluate the various proposals, comparing the proposals using the above results. The Legislature identified three criteria that any successor tariff must satisfy:

- Ensure sustainable growth of on-site customer renewable generation;[12/]
- Base the tariff rate on costs and benefits of the generator;[13/] and
- Ensure that total benefits to all customers and the electrical system approximately equals total costs.[14/]

Each of the three criteria is examined below. PG&E does not repeat here the arguments in its Proposal supporting our determination of the most appropriate metric to measure the extent to which a given proposal satisfies a given criterion.[15/] Rather, PG&E focusses on examination of metrics proposed by others that are inappropriate or misleading. Table 6, below, summarizes the metrics proposed by parties for each of the legislative requirements for a successful successor tariff. PG&E has split the first criterion (ensure sustainable growth) into two critical features. As discussed in our proposal, "growth" is a different characteristic from "sustainable," and a different metric is necessary for each. The market will grow whenever customers choosing renewable generation can receive a value proposition sufficient to motivate their choice and vendors can earn sufficient return by selling their products at prices that are acceptable to customers; whereas a given proposed successor tariff can only be considered sustainable if it seriously addresses the rate impacts of a participant's choice to install renewable generation. Only proposals that satisfy both metrics can be considered compliant with Legislative direction to "ensure sustainable growth. In Table 5, where parties did not draw a similar distinction, "Included in Growth" appears in the column headed "Sustainable." As described in PG&E's

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12/ Section 2827.1(b)(1).

13/ Section 2827.1(b)(3).

14/ Section 2827.1(b)(4).

15/ See sections II.B and II.C of PG&E's August 3rd Proposal.

previous comments in this proceeding, the Public Tool does not allow users to assess the supply-side or vendor perspective, as it does not provide a cost basis upon which a margin can be inferred. As discussed in more detail later in these comments, PG&E believes the question of vendor margins is a critical one that should be assessed when setting policy, since vendor margins are higher in California than in nearby states, as demonstrated in Appendix B.

Table 6: Comparison of Suggested Metrics to Evaluate Legislative Compliance of Proposals

Party	2827.1(b)(1) "Growth"	2827.1(b)(1) "Sustainable"	2827.1(b)(3) "Facility"	2827.1(b)(4) "customers and electrical system"
PG&E	PCT Vendor Margin	RIM	PCT	RIM
SDG&E	PCT + RIM	Included in Growth	COS	COS
SCE	RIM	RIM	RIM	RIM
ORA	PCT Payback	RIM	RIM	RIM
TURN	5,000 < MW < 12,000; Payback PCT	Included in Growth	PCT for VODE + DGA	RIM for VODE
NRDC	MW	No "significant" cost shift	Benefits + Costs Equal	PCT, RIM, PAC, TRC, SCT
Solar Parties	Year over Year growth	Included in Growth	PCT is "adequate"	Enhanced TRC; Enhanced SCT
TASC	Year over Year growth to match s-curve	Included in Growth	PCT	Enhanced TRC supplemented with Enhanced SCT
CalSEIA	Installed MW	Included in Growth	Subsumed in (b)(4)	Enhanced TRC and Enhanced SCT; RIM "close to" 1.0
Sierra Club	"robust" MW	Included in Growth	Subsumed in (b)(4)	Enhanced TRC and Enhanced SCT
FEA	"robust" MW	Included in Growth	TRC plus RIM	TRC

1. The Total Resource Cost (TRC) Test and Societal Cost Test (SCT) Are Not Relevant for the NEM Successor Tariff to Satisfy the Legislative Intent.

The proposals of parties who want a just and reasonable NEM successor tariff are starkly different from the proposals of parties representing solar vendors and the status quo. The latter simply ignore cost shifts from participating solar customers to non-participants by focusing solely on the TRC and SCT tests (neither of which are at all sensitive to cost-shifting).

a. The TRC is the Wrong Metric To Measure Whether The "Total Benefits To All Customers And The Electrical System Approximately Equals Total Costs."

CalSEIA asserts Section 2827.1 does not require the Commission to consider the RIM test in designing the NEM successor tariff.[16/] CalSEIA interprets the absence in AB 327 of the words "preserve ratepayer indifference" as justification to totally ignore the impact on non-participants. CalSEIA twists the logic of the legislation's instruction to consider the impact on "all customers" as justification to favor participating solar customers at the expense of non-participants.

Obviously, the impact on "all customers" includes the impact on non-participants as well as participating solar customers. According to the Standard Practice Manual, the RIM test represents the impact on rates (which fall mostly on nonparticipants) and the PCT represents the participants' perspective. CalSEIA interprets "all customers" to justify using the combination of the RIM test and PCT in the form of the TRC test that "represents the combination of the effects of a program on both the customers participating and those not participating in a program."[17/] This is misleading, because the rate impacts do affect all customers. By combining the non-participants' test (RIM) with the participants' test (PCT) into the TRC—and its extension, the Societal Cost Test (SCT)—the cost impact on millions of non-participants is canceled by the benefits on hundreds of thousands of participating solar customers. Put simply, the TRC and the

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16/ CalSEIA pp. 14-15.

17/ California Standard Practice Manual, October 2001 at 18.

SCT will calculate exactly the same value, no matter what the underlying rate design is, if all other things are equal.[18/] Obviously the legislature did not intend the CPUC to analyze a tariff using metrics that do not change as the tariff proposals changes.

b. The SCT is the Wrong Metric To Evaluate Whether The "Total Benefits To All Customers And The Electrical System Approximately Equals Total Costs."

(1) The SCT is for High-Level Policy Making And Not Program Approval.

Sierra Club and the solar parties (the Sierra Club Report)[19/] advocate consideration of a long list of claimed societal benefits. Doing so will unduly burden customer rates with costs for which customers do not receive offsetting benefits. The CPUC has considered these arguments in prior proceedings and rejected them.[20/]

Choices of how to design NEM should be evaluated exclusively on avoided costs and benefits which flow to utility customers. Even if there are some societal benefits, PG&E does not believe that societal benefits should be considered in cost-effectiveness screening for NEM. Funding claimed benefits like "land use benefits" will result in the misallocation of resources, with utility customers being burdened with 100% of costs for which they receive only a fraction of offsetting benefits, assuming those benefits are even actually achievable.

In any case, the Standard Practice Manual did not envision the SCT being used to design rates. Rather, where it is used at all, the SCT is more appropriate for informing high-level,

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18/ The reader will note that Table 4, which is a comparison of proposals using the same input assumptions, does not have the same TRC value, even though the input assumptions are the same. That result is driven by the fact that different proposals will change factors like who installs generation (residential or nonresidential); and when it is installed (this year or next year or 5 years from now). For example, because the per-kW costs are higher for smaller installations, the TRC will be lower if residential installations are higher under one proposal than under another.

19/ See Attachment 2 of the Sierra Club proposal titled, "Non-Energy Benefits of Distributed Generation Inputs for Use in NEM Successor Tariff Proceeding" by Alison Seel (Sierra Club) and Tom Beach (Crossborder Energy).

20/ D.09-08-026.

policy decisions.[21/] However, in the case of NEM, the policy decision is moot. The legislature has already decided to support rooftop solar. This proceeding is focused on deciding on how best to design the tariff for such arrangements. It is inappropriate for the SCT to play a role in that decision. The Legislature could not have intended the use of the SCT to evaluate different tariff proposals, as the SCT does not consider any aspect of the underlying tariff structure when evaluating benefits and costs. That is, exactly the same result would ensue no matter what proposal was evaluated, all other things being equal.

If, however, the Commission chooses to consider the SCT in designing the NEM successor tariff, then the actual dollar value of "societal benefits" given to these claims needs to be vetted in hearings. Even if the societal benefits asserted by Sierra Club Report-- reductions in the air pollution, improvements in human and environmental health, reduced water use, reduced land use, power system resiliency, economic stimulation—were consensus-based and well-defined and not illusory, basing a NEM successor tariff decision on a Societal Cost Test would burden investor-owned utility customers in California with higher rates to pay for the cost of alleged benefits to be received, if at all, by other customers in California, in other states, and beyond.

(2) The SCT Includes Ill-Defined And/Or Illusory Benefits

SEIA/Vote Solar ask the Commission to give specified values for asserted benefits such as such as "health benefits," "land use benefits," "enhanced reliability and resiliency," and "water use."[22/] They also claim that new solar provides "market price mitigation."[23/] Similarly,

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21/ For example, the SCT could provide important directional information to a state considering whether to adopt an RPS standard. In California, we are well beyond the stage of *whether* to support renewable customer generation –California leads the entire nation in this important policy. The CPUC is asked *how* to implement this policy without undue impact on rates – thus the SCT is not the appropriate test.

22/ SEIA/Vote Solar pp. 28-30.

23/ SEIA/Vote Solar p. 27.

the Sierra Club relied extensively on claimed Societal Benefits.[24/] This is not the first time parties have sought consideration of the claimed "societal" benefits of solar and other renewable generation. In 2005, the CPUC held extensive hearings on how to conduct a cost-benefit analysis of Distributed Generation (DG). Many parties asked the CPUC to consider and adopt a similar "waterfall" of benefits of DG, including claimed benefits they called "Political, Locational, Environmental, Antidotal, Security, and Efficiency attributes of DG", or the "PLEASE matrix." These specifically included claimed health, job, tax, and other benefits claimed to be created by DG. The utilities explained that many of these claimed benefits should not be included in the analysis either because benefits/costs do not exist or cannot be quantified at this time, or because they are already included elsewhere (e.g., in the avoided energy and capacity values).

The CPUC rejected most of these claimed benefits as part of the RIM test in its cost-benefit decision, D.09-08-026.[25/] The CPUC included a small reliability adder already in use in the Standard Practice Manual, but rejected adding an additional value to the customers using self-generation as a back-up power supply, both because most DG units provide no such benefits (the units trip off-line when the grid is disrupted) and because the CPUC has no method of quantifying such values.[26/] The CPUC also rejected claims of employment and tax benefit effects, stating that it had no method to evaluate whether DG installations would create more jobs than those displaced, as well as an inability to quantify the value of such claimed benefits.[27/]

24/ Sierra Club pp. 1, 2, 5-8, 10, and Attachment 2.

25/ The decision did find that "We find the Societal Test, as presented in the Itron Framework, … provides a useful perspective in assessing the costs and benefits of DG projects and programs." D.09-08-026. However, it made no findings about how to calculate such measures, and rejected consideration of them in the RIM test at issue here.

26/ D.09-08-026, p. 39.

27/ D.09-08-026, p. 40. PG&E explained at hearings that to the extent DG programs increase electric rates, this could have a negative impact on employment and taxes, as higher electric rates may drive jobs away from California. These factors are not used in any other Commission avoided cost calculations.

The CPUC's work here is required to fulfill the requirements of Assembly Bill (AB) 327 which specifically focuses on the rate impact of NEM to non-participating customers. Therefore, the request to consider these items here should exclude the broader societal benefits these parties now seek to have the Commission include, since they have no beneficial rate impact. The Commission should continue to reject use of these measures to design the NEM successor tariff.

(3) The SCT Benefits Claimed By Solar Parties Are Inappropriately Included.

Several of the benefits claimed by the Sierra Club and Solar Parties are inappropriate. Most blatantly, soft costs of solar (marketing, installation, permit fees, etc.) dated from 2013 are assumed to be a societal benefit attached to all solar installed in the future, regardless of how soft costs fall over time.[28/] Even if one accepts the dubious notion that spending on solar soft costs represents a true societal benefit (rather than merely displacing spending that would occur elsewhere in California's economy), this value should account for the reductions in soft costs that have occurred since 2013 and that will continue to occur through 2025. It is also worth noting that the soft costs highlighted by the Sierra Club include permit fees paid to county inspectors, which are clearly a transfer payment. By the same logic, the Sierra Club paper should also deduct the recently extended property tax exemption for solar as a societal cost.

Additionally, the Sierra Club paper inappropriately mixes benefits specific to California (e.g., federal tax credits) with benefits coming from outside California (e.g., national carbon emissions abatement). This is inconsistent. The Sierra Club cannot claim the California impact of federal tax credits as a benefit of solar while at the same time also trying to claim a carbon emissions abatement benefit calculated for the entire country, including impacts exogenous to California. If the Sierra Club and Solar Parties wish to claim such benefits, they must demonstrate versions of those benefits that are limited to California. If they do not, any claimed benefits exogenous to California are improper and should be rejected at the outset. As

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28/ Sierra Club, p. 12.

SEIA/Vote Solar explained in their own Proposal, the claimed societal benefits they rely on are clearly material and add 10.9 to 13.3 cents per kWh to the levelized benefits of DG development from 2017 to 2025.[29/]

2. The Ratepayer Impact Measure (RIM) and Participant Cost Test (PCT) Should Be The Primary Metrics for the NEM Successor Tariff to Satisfy the Legislative Intent.

a. RIM is the Correct Metric For Sustainability And Impact On "All Customers."

Parties advocating reform look to the RIM test as the only correct measure of whether or not benefits approximate cost for customers and the electrical system as required by section 2827.1(b)(4). In its June 3, 2015 staff paper, Energy Division acknowledged the Commission has a well-established history of using the RIM test to evaluate the costs and benefits of NEM.[30/]

CalSEIA claims that "The Legislature made a conscious decision not to direct the Commission to include impacts on non-participating ratepayers as one of the statutory criteria in Section 2827.1(b)." It claims

> During consideration of AB 327, the Legislature took the specific action of stripping language from the bill that directed the Commission to "Preserve nonparticipant ratepayer indifference." The September 3, 2013 amendments replaced that language with the current language in section 2827.1(b) on sustainable growth, disadvantaged communities, and the need for costs to be approximately equal to benefits.[31/]

It is correct that the language in the bill was amended on September 3rd, but flatly incorrect that the new language was intended to remove any interest in preventing cost shifting. The new language said that costs were to be "approximately equal to benefits" and the legislature continued to explain that this language was still designed to address and protect against cost

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29/ SEIA/Vote Solar p. 30.

30/ Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract (Staff NEM Successor Whitepaper), June 3, 2015, p. 1-10;"The Commission has a well-established history of using the RIM test to Evaluate the costs and benefits of NEM." http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M152/K410/152410786.PDF.

31/ CalSEIA pp. 14-15.

shifting. After the language now in section 2827.1(b)(3) and (4) was put in print, the legislative committees considering AB 327 twice reported that in designing the new NEM rules "The PUC will be required to ensure that the new standard contract or tariff for rates, terms of service, and billing rules is based on the electrical system costs and benefits received by nonparticipating customers and prevents a cost shift to non-NEM customers."[32/] The claim that by adding this language, the legislature intended that **cost shifting not even be considered,** is obviously contrary to this clear legislative history.

The determination of Legislative intent is further informed by a letter from the author of AB 327 to the President of the CPUC at the time the first NEM reform-related issue was under consideration at the CPUC (grandfathering of existing solar customers). In that letter Assembly Member Henry Perea said "I am concerned the proposed decision fails to meet the original intent of AB 327 with respect to the potential cost shift customers could face. During last year's negotiations the Legislature's intent was clear that we wanted to limit the cost shift to a more fair and equitable rate design regardless of a customer's decision to become a customer-generator."[33/]

By design, the TRC and SCT tests ignore cost-shifts among utility customers. Obviously, the intent of NEM successor tariff proceeding is not to ignore cost-shifts, but rather, to put them front and center when choosing a just and reasonable NEM successor tariff that minimizes cost-shifts to non-NEM customers. In any case, it would be a failure of policy if a NEM successor tariff can only succeed with massive cross-subsidies from non-NEM customers. The RIM test was designed to evaluate programs which account for onsite reductions in usage and have no exports to the grid. That is why the RIM test is equally critical to the CPUC's decision making and is the appropriate measure of compliance with § 2827.1(b)(4), for reasons discussed above.

32/ Senate Floor Analysis, September 3, 2013, p. 4; Senate Floor Analysis, September 6, 2013, p. 4.

33/ Assembly member Henry T. Perea letter to President Michael Peevey dated February 26, 2014.

To the extent a perceived inconsistency of results exists between the RIM test and the TRC and SCT tests, CPUC should rely on the RIM test. Non-NEM customers cannot avoid incurring cost-shifts from NEM customers, while participating customers do have a choice. The RIM test reveals such a cost-shift. The policy goal in this proceeding is to achieve a just and reasonable NEM successor tariff for all customers. Customers should have an incentive to install solar, but not to the further detriment of non-NEM customers who are subsidizing the current NEM program, and will continue to do so throughout the transition period.

Solar parties argue that programs such as SASH, MASH, and the green tariff shared renewable (GTSR) program have widened access to distributed solar enough that cost-shifts from NEM (as revealed by the RIM test) are not relevant.[34/] While it is true that these programs enable more customers to participate in the advancement of solar in California, it is absurd to say that (for instance) an apartment dweller having access to GTSR, a program that explicitly forbids cost shifting, makes them indifferent to rate increases resulting from the relatively narrow set of customers able to adopt DG. To the extent that the NEM program does increase rates, the CPUC must ensure they are reasonable.

Finally, several of the parties opposing consideration of the RIM test argue that if it is considered, the Commission should only consider the impacts under the "export only" model, and not the "all generation" model.[35/] However, this should be rejected because the purpose of the RIM test is to gauge the cost shift from participating customers to non-participants. Additionally, a NEM customer is off-setting its rates, and therefore not contributing to the costs of service whenever their system is generating and not just when it is exporting. As the CPUC explained in its 2013 report to the legislature, "the entire NEM generation is the appropriate

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34/ SEIA/Vote Solar p. 11, TASC p. 28.

35/ SEIA/Vote Solar, p. 31.

scope to measure the impact on non-NEM customers."[36/] Just as a customer installing energy efficiency to reduce its load, and bill, will create an impact on rates, so too does the generation that meets the customer's own behind-the-meter load. Moreover, the existing NEM program has components that have nothing to do with exports (exemption from NBCs, standby fees, and interconnection costs).

b. PCT is the Correct Metric For Economic Growth And Impact On The "Electrical Generation Facility."

Again we see a clear distinction between parties suggesting that the CPUC need take no action and parties who recognize the need for reform. Supporters of a reformed NEM program typically identify the PCT as the appropriate measure of participant value that will ensure growth. TURN and ORA also include payback as a measure and TURN and NRDC also would consider actual adoption. PCT is obviously the measure of customer economic opportunity. TURN and ORA advocate for a PCT greater than 1.0. PG&E's suggestion of a slightly higher PCT to measure the economic opportunity for customers is predicated on the use of appropriate solar pricing assumptions as represented in the "low cost" scenario.

PG&E has also advocated for a measure of sustainability from the supply side or vendor perspective. As with any market, it is important to understand the impacts on both sides of the economic equation. However, there is currently no mechanism by which parties can measure the incentive for vendors to sell products under the tariff, because the Public Tool does not calculate vendor margins. This omission in the Public Tool leaves the CPUC unable to fully assess whether a tariff can facilitate a sustainable market from both the customer (demand) and vendor (supply) perspective.

36/ The CPUC stated in its October 2013 California Net Energy Metering Evaluation that the "export only" case disregards the NEM generation consumed on the customer premise, and concluded "To the extent NEM compensation enables the whole DG project to be viable, and the total output of the project results in a cost to non-NEM customers, the entire NEM generation is the appropriate scope to measure the impact on non-NEM customers." (page 3).

The Status Quo parties, by suggesting the current NEM tariff needs no modification, have ignored any distinction between growth and sustainable growth, with the result that year-over-year adoption or "robust" adoption inappropriately becomes the measure for "sustainable." As most reform proponents recognize, and as the Energy Division recognized, this is simply not the case. Almost all reform parties recognize that minimizing rate impacts is essential for sustainability and RIM is the appropriate metric to measure that.

c. Projected Year Over Year Growth Is Not An Appropriate Metric Here.

SEIA/Vote Solar argue that "sustainable growth" of renewable DG means that, in the near term, the year-over-year growth in solar MWs installed should equal or exceed the growth in the prior year, in order to match the appropriate slope of the logistic adoption curve.[37/] However, as the CPUC has recognized, and as the Energy Division recognized in its White Paper, it is beyond the power of the CPUC to design a tariff that will ensure year-over-year growth. In fact, a tariff alone cannot ensure any amount of growth since the market is driven by too many factors outside of the CPUC's control. On the other hand, the CPUC can design a tariff that ensures that customers have an economic opportunity under the adopted tariff, and that vendors continue to have sufficient and/or appropriate economic incentive to provide DG related products.

C. The Proposals For No Change Should Be Rejected

1. Claims That There Will Be Little to No Cost Shifting Under The Current NEM Design Are Meritless

In arguing that no changes are needed to the existing NEM structure, TASC, SEIA-Vote Solar, CalSEIA, and the Sierra Club (the Status Quo Parties) made numerous unwarranted and/or erroneous changes to the Public Tool. Taken in their entirety, these changes drive modeling results completely at odds with the Commission's bookend scenarios and the independent

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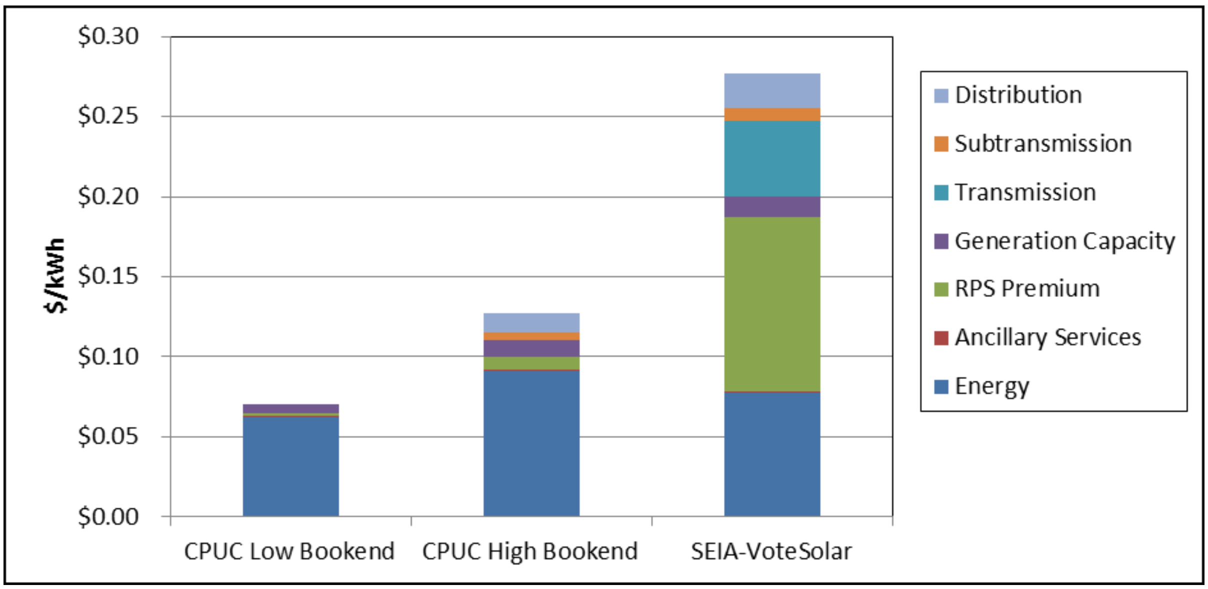
37/ SEIA/Vote Solar p. 8.

scenarios presented by other parties. In their effort to minimize the immense cost shift calculated by the Public Tool in more reasonable scenarios (including the Commission's own bookends), the Status Quo parties achieve unrealistic cost savings attributed to DG. As seen in the figure below, the resulting avoided cost estimates are double that of the Commission's high bookend values. Notably, the proposed "Avoided RPS Premium" value exceeds that of utility scale solar prices cited in the most recent Padilla Report.

With rare (and insignificant) exceptions, these suggested changes are completely unjustified and represent significant divergences from previous cost effectiveness analyses of DG, as shown by Figure 1.

Figure 1: Avoided Cost Comparison of CPUC Bookends and SEIA/Vote Solar[38/]



a. Avoided Energy Cost and Capacity Costs

SEIA/Vote Solar made many changes to the default assumptions in the Public Tool, many of which result in an increase in the avoided energy cost. The table below captures some of these issues:

38/ Uses Two Tiered Residential Rates with Existing NEM as baseline scenario.

Table 7: SEIA/Vote Solar Changes to Default Assumptions in the Public Tool

Input	Default	Solar Alternative	Comment
Cost of CCGT Capacity	$157/kW-yr.	$176/kW-yr.	The source is no more recent than the E3 analysis supporting the original numbers.
Cost of CT Capacity	$172/kW-yr.	$190/kW-yr.	
Gas CCGT Heat Rate	7150 BTU/kWh	7400 BTU/kWh	
Gas CT Heat Rate	8750 BTU/kWh	9500 BTU/kWh	
Gas CT Economic Life	20 years	30 years	Inconsistent with the economic life assumed by E3 for a CT when performing cost calculations
Fossil Steam Capacity Factor	10%	5%	This input is inactive in the RR Model, making this change unnecessary.
Locational Energy Value Adder	0	2-4.5%, depending on solar party	Geographic pricing inaccuracies are negligible compared to the temporal inaccuracies.
Market Price Mitigation	0	$0.005/kWh of DG gen	Previously rejected by CPUC in DG Cost-Benefit Proceeding

SEIA/Vote Solar Attachment A2. Similarly, TASC and CalSEIA made many changes to the Public Tool assumptions.[39/]

i. Fossil Plant Characteristics

Citing the CAISO's "2014 Annual Report on Market Issues and Performance," the Status Quo parties increased the costs and heat rates of new fossil plants, increased the economic life of gas CTs, and reduced the capacity factor of steam generators. Regardless of the merits of these

39/ See TASC Appendix A; CalSEIA Appendix A.

changes, the net impact on avoided costs is very low. First, the steam capacity factor input is not used for anything in the Public Tool, making that a pointless change that only serves to exaggerate the differences between parties' input assumptions. For the changes that could have any impact, PG&E ran the CPUC High Bookend with two tiered rates and existing NEM while making these changes. Compared to the results of the unmodified high bookend, avoided costs increase by $0.0025/kWh, or 1.96%, due to these changes. In a scenario which does not assume a 2017 Resource Balance Year (PG&E believes it is more appropriate for this to be determined in the Public Tool), we expect that these impacts will be far more muted.

While the 2014 CAISO report mentioned above was not available until recently, the 2013 version has been available for the entire NEM Successor Tariff proceeding. This report has identical CCGT and CT costs and heat rates as the 2014 report, as both cite the "March 2013 CEC Workshop on the Cost of New Renewable and Fossil-Fueled Generation in California." As such, this was information that E3 would have had (and likely referenced) when developing the assumptions for the Public Tool. Given how small the impact is and the reasonableness of the original inputs, PG&E does not believe this to be a necessary change to the inputs of the model.

ii. Energy Cost Forecast and the Locational Value Multiplier

The Status Quo parties increased the E3 Public Tool forecast of system energy prices by 2% to 4.5%, while PG&E, (despite not altering the Public Tool default energy prices) argued that the energy cost forecast in the Public Tool is already too high.[40/] Avoided energy is typically the largest avoided cost component associated with NEM generation, so changes to this variable should be examined carefully.[41/]

The rationale for these increases by SEIA/Vote Solar to energy prices is that the E3 Public Tool does not capture locational variation in energy prices due to congestion. While this

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40/ PG&E Proposal p. 41 and Appendix A p. 73.

41/ See for example, Tables 16-19 of the June, 3, 2015 CPUC Energy Division Staff Paper on AB 327 Successor Tariff or Standard Contract.

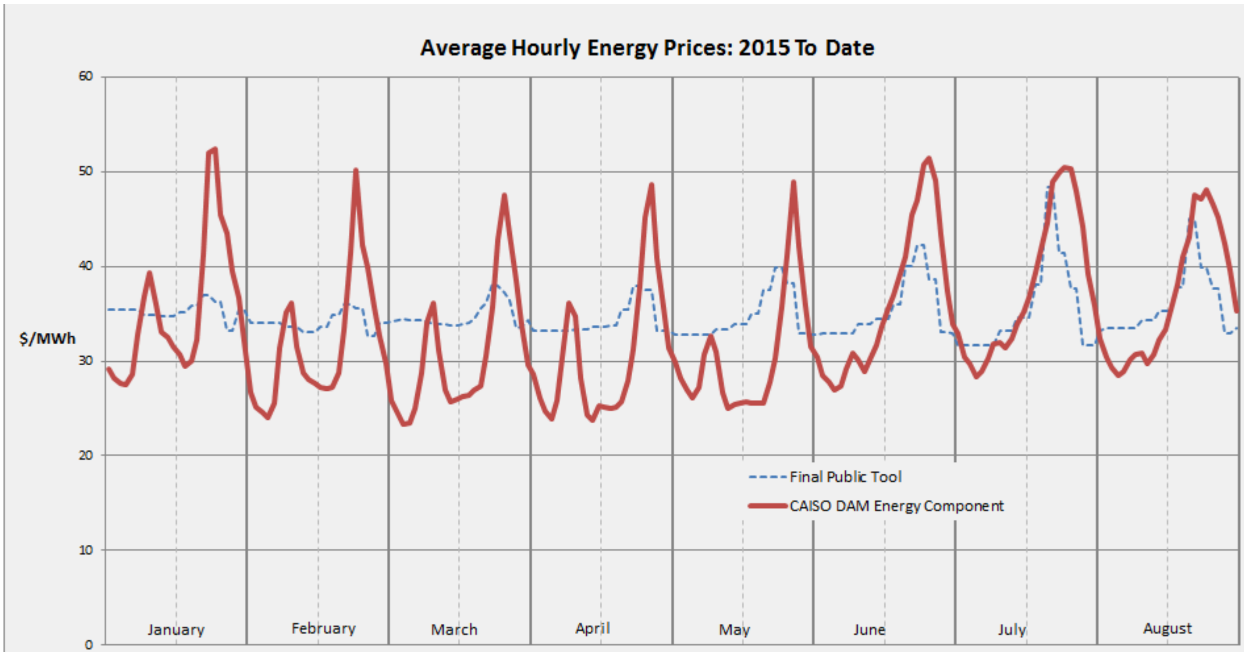
is true, PG&E notes that the actual impact of congestion on avoided energy cost is complicated by the utility's ability to hedge against those costs using Congestion Revenue Rights. More fundamentally, however, the locational variation in pricing is small[42/] and is dwarfed by the temporal variation in pricing. The Public Tool's inability to capture this temporal variation has a far greater impact on the energy avoided cost than locational price variation does.

PG&E has compared the avoided energy cost (benefit) for 2015 to-date using actual market prices and has found that the Public Tool energy prices result in an energy avoided cost which is approximately 13% too high. This is despite the current low hydro conditions, which would be expected to drive prices up. As discussed below, PG&E expects, based on public modeling results, that the discrepancy between mid-day energy prices forecasted in the Public Tool and actual prices will increase as solar generation continues to grow. By 2020 the Public Tool energy avoided cost is more than double PG&E's estimate.

Even without the adjustments by SEIA/Vote Solar under current conditions, the Public Tool energy price forecast compared to current market prices is high in middle of day. The model's price forecast starts in 2012, so we are able to see prices that the model produces in 2015 and compare to actual prices. The chart below provides this comparison. The curves represent a monthly average of the energy price in each hour (i.e. an average hourly price curve for each month). The Public Tool produces prices which are fairly flat, especially in non-summer months, while the market prices are significantly lower in the middle of the day (the dotted lines mark noon, PST) and significantly higher in the evening hours. This mid-day price dip is especially pronounced in spring months, yet does not show up at all in Public Tool price forecast. The peak of prices from the Public Tool (i.e. the hour with the highest price of the day) is also one to three hours earlier than the peak of actual market prices, for all months to date in 2015, thus giving too much value to solar's noon-peaking generation.

42/ In a June 2015 filing at FERC, the CAISO described this price dispersion as "de minimis." That filing is available here: http://www.caiso.com/Documents/Jun3_2015_ComplianceFiling_LoadGranularityRefinements_ER06-615_ER02-1656.pdf.

Figure 2: Comparison of actual hourly energy prices and hourly energy prices modeled by the Public Tool For All Months to Date in 2015.[43/]



In order to quantify the avoided cost using these two price curves, PG&E used the aggregate PG&E Behind-the-Meter (BTM) PV profile developed by the CAISO for its LTPP Plexos model to compare the energy avoided cost of a rooftop PV system using these two different energy price forecasts. This price discrepancy results in an overestimate of approximately 13% in the energy avoided cost for 2015 to date.

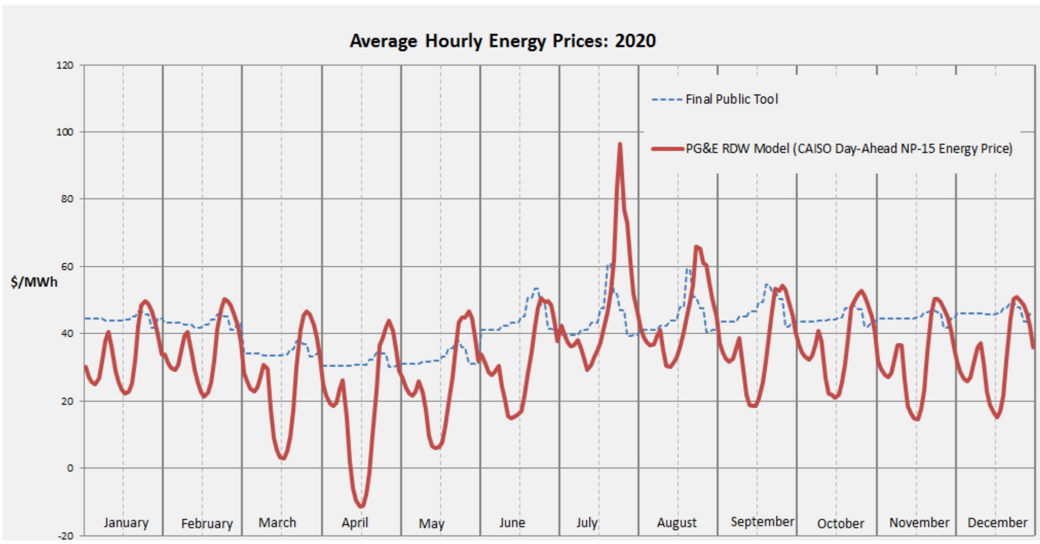
Moreover, the price discrepancy in the middle of the day increases dramatically over time. PG&E provided, earlier this year, a public electricity price forecast and forecasting tool for the 2015 Rate Design Window (RDW) proceeding. This electricity price forecast was considered acceptable by SEIA, for setting the time of use (TOU) windows in the RDW proceeding.[44/]

43/ These prices are nominal, with the base gas price used in the Public Tool. During this period, the average of CAISO's gas price index for PG&E territory is $3.39/MMBtu, slightly lower than the $3.50 used in the Public Tool (RR Calculation tab, cell M3027).

44/ In testimony on behalf of SEIA, R. Thomas Beach used PG&E's model to forecast NP-15 market prices to analyze hourly Marginal Generation Costs for evaluating different TOU windows. May 1, 2015 Testimony on behalf of SEIA, in Application 14-11-014, pg. 12.

We are able to compare the price forecast from this tool for 2020, when the state is at its 33% RPS target, with a price forecast from the Public Tool under the same conditions. This comparison is depicted in the graph below.

Figure 3: Comparison of hourly energy price forecasts modeled by the Public Tool and by PG&E's RDW Model For All Months in 2020.[45]



Clearly, both the mid-day price dip and the evening spike have increased significantly in PG&E's forecast, yet the Public Tool energy price forecast shows no mid-day price dip and only a modest (and too-early) evening spike. Using the CAISO's BTM PV profile to again compare the energy avoided cost of a rooftop PV system using these two different energy price forecasts in 2020, this price discrepancy now results in a 106% overestimate in the energy avoided cost.

The price discrepancies in the middle of the day and the evening also increase dramatically under higher RPS Scenarios. In the 2014 LTPP, CAISO modeled a 40% RPS by 2024 scenario in Plexos.[46] This scenario is analogous to the Public Tool 50% RPS price

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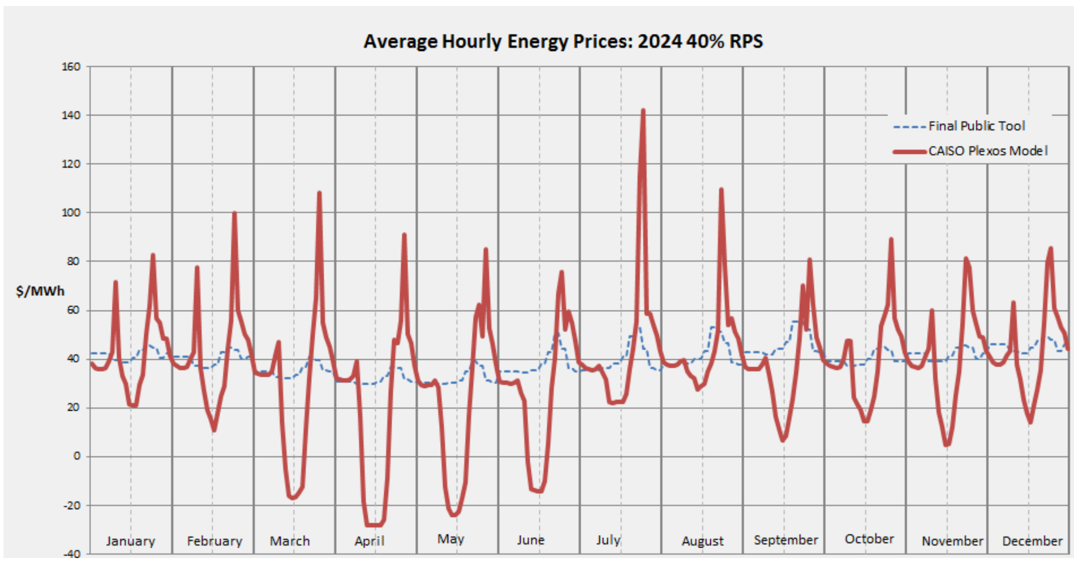
45/ Prices are nominal. The Gas and GHG prices used in PG&E's RDW model were changed to be the same as the price used in the Public Tool (this is held constant for 2020 at $4.52/MMBtu from cell R3027 and $16.16/tonne from cell R3031, both in the RR Calculations Tab of the Revenue Requirement model).

46/ Additional information on this modeling effort is available in the CAISO LTPP Testimony provided here: http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf.

forecast in 2024, since the 50% RPS scenario has a 40% RPS penetration in 2024. The chart below provides a comparison between the monthly average price curves in 2024 produced in the Public Tool and those produced in the CAISO Plexos model. Again, the Public Tool produces a relatively flat price forecast which does not capture the mid-day price dip or the evening price spike after the sun has gone down.

Figure 4: Comparison of hourly energy price forecasts modeled by the Public Tool and by the CAISO Plexos Model For All Months in 2024.[47/]



47/ While PG&E was not able to change the gas prices in the CAISO's Plexos model, PG&E notes that an average PG&E gas price used in this model is $4.75/MMBtu, which is lower than the gas price used in the Public Tool ($5.22 in cell V327 of the RR Calculations tab of the Revenue Requirement model). PG&E did impose a price floor of -$30/MWh to be consistent with the RDW model assumptions and a price cap of $555/MWh to eliminate extreme penalty prices during three shortfall events.

Using the CAISO's BTM PV to again compare the energy avoided cost of a rooftop PV system using these two different energy price forecasts in 2024, this price discrepancy now results in a 673% overestimate in the energy avoided cost.

Clearly, getting the temporal variation of electricity prices right is critical to getting the energy avoided cost right and should be a higher priority than capturing the minor and complicated effects of locational variability in prices on energy avoided cost. Unfortunately, the Public Tool does not capture this temporal variability. The effort of the Status Quo parties to move the avoided cost calculations in the opposite direction should be rejected.

iii. Market Price Mitigation

SEIA/Vote Solar ask the Commission to give specified values for asserted benefits such as such as "market price mitigation"[48/] or the ability to reduce the market price of electricity. This asserted benefit, also called a price elasticity adder, is premised on the idea that the installation of DG lowers customers' net demand, and thus reduces the market price of electricity.

The CPUC rejected similar claimed benefits as part of the RIM, TRC and SCT tests in its cost-benefit decision, D.09-08-026.[49/] The Commission should continue to reject this claim for the following reasons. First, if we assume any generation capacity is imbued with such a benefit as price elasticity/mitigation effects, market performance benefits, reliability impacts, and hedge or insurance value, the avoided generation capacity cost benefit already in the Public Tool also will be imbued with these same such benefits of capacity.

Second, DG is a source of supply that offsets existing demand. If supply and demand are in balance in the market prior to the installation of the DG unit, its installation hopefully will cause a central station generation unit to operate less. However, the Resource Adequacy (RA)

48/ SEIA/Vote Solar p. 27.

49/ The decision, D.09-08-026, made no findings about how to calculate such measures and rejected consideration of them in the RIM, TRC and SCT tests.

value of a central station generation unit is a function of both its costs and the revenues it receives from the market. To the extent a central station unit receives less revenues in the market to offset its fixed costs, its RA price must increase to replace that lost market revenue, thus negating any alleged benefit.

b. Avoided RPS Cost

SEIA/Vote Solar and others have altered the Public Tool in a way that does not accurately present the avoided RPS benefit of NEM generation. Under current policy, NEM generation avoids RPS cost by reducing energy sales: for every MWh of reduced sales, the utility procures 0.33 MWh less of RPS eligible energy. This is because the RPS procurement requirement is 33% of energy sales. The same approach would be applied under different RPS percentages. In other words, the applicable RPS percentage is multiplied by NEM generation sales reduction to arrive at the avoided RPS procurement. The Status Quo parties have simply deleted the RPS percentage multiplier in the avoided cost calculation.

SEIA/Vote Solar's alterations result in a valuation of the avoided RPS cost (benefit) as though NEM generation reduces RPS procurement on a 1-for-1 basis, that is 1 MWh of NEM generation avoids procurement of 1 MWh of RPS procurement, which is valued at the RPS premium calculated in the Public Tool.[50/] **However, the SEIA/Vote Solar's alteration did not account for the RPS procurement cost associated with NEM production no longer reducing sales (thus increasing RPS procurement) when the Public Tool calculates RPS procurement requirements.** The end result is that SEIA/Vote Solar over-states the RPS procurement benefit by 200% compared to current policy, and by 50% if NEM production is correctly treated as offsetting RPS procurement on a consistent basis with larger-scale renewables.

In order to accurately model a scenario in which NEM generation offsets RPS on a consistent basis with large renewable generators – a policy change which PG&E supports - the

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50/ SEIA/Vote Solar pp. 16-23, detailed description of changes to the model on p. A-3. Also CalSEIA p. 31.

RPS procurement must actually be reduced while at the same time, the sales which are offset by the NEM generation should be added back in to the sales baseline which is used to calculate the RPS requirement.

This overvaluation of avoided RPS is compounded by the following input choices that are used by the Status Quo parties:

1. Base Solar Cost Case
2. No curtailment of Renewables during Overgeneration

Regarding RPS prices, the May 2015 "Padilla Report to the Legislature"[51/] summarizes post-Time of Day weighted average Solar PV and Wind RPS contract prices in 2014 provided by the CA IOUs. In 2014, the utilities signed contracts at $72.2/MWh for solar PV energy and $61.8/MWh for wind energy. For comparison with the Public Tool prices, which are all in 2013 dollars, we convert these to 2013 dollars using the 2% Public Tool assumption for inflation, yielding $70.7/MWh for Solar PV and $60.6/MWh for wind.

For comparison, the Public Tool price input for 2014, assuming the "base" Solar Cost Case is 94.5/MWh for solar PV and $85.74/MWh for wind. Over time these prices stay essentially flat in real dollars, before jumping up even higher in 2017 due to the forecasted decline in the Investment Tax Credit. The only Solar Cost Case which includes an RPS price in any year that is close to the recent Padilla Report prices is the Low case. The wind price forecast never reaches a level close to these recent prices. Therefore PG&E finds that the Public Tool price forecast is generally high, and is especially high for Solar PV under the Base and High Solar Cost cases.

While the limited data in the most recent Padilla Report only enables a comparison of solar PV and wind contract costs, these resources make up the majority of the RPS portfolio in

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51/ Located here: http://www.cpuc.ca.gov/NR/rdonlyres/7AB50CCF-C438-4BE7-A008-1AC6E4A22A5C/0/FINALPadillaReport2015PUBLICFINAL.pdf.

the Public Tool.[52/] PG&E provides additional evidence that the base and high Solar Cost Cases are unrealistically high on pages 44-47 and 76-81 of its NEM Successor Tariff Proposal.

Regarding curtailment of renewable energy during over-generation periods, the Public Tool reduces the avoided RPS cost associated with NEM to account for NEM generation that occurs during periods of forecasted RPS curtailment; however, the user can assume that all curtailed RPS energy would instead be exported to other states by choosing the No Curtailment option. The Status Quo parties make the latter assumption. As discussed below, recent work by E3 and others suggests this assumption is unreasonable and therefore its use would result in overestimated avoided RPS values.

In contrast, PG&E finds that overgeneration can result in significant curtailment, especially under higher renewable penetration scenarios, and even when models are allowed to export excess energy.

There is currently no historical precedent that supports any amount of net export from the CAISO system: The CAISO, in its 2014 LTPP Testimony used a "no net export" constraint in its 2024 models of the California power system on the basis that net export from CAISO has never occurred in the past as well as an observation that movement from day-ahead import/export schedules has historically been limited.[53/] As a result, the CAISO's 2024 model is forced to curtail daytime renewable energy in 1% (under a 33% RPS) to 9% (under a 40% RPS) of hours in the year.

Earlier E3 work in the *Investigating a Higher Renewables Portfolio Standard*[54/] study finds that, even if export is allowed, curtailment is not avoided. In this study, exporting from

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52/ See rows 212 – 258 of the RR Inputs tab of the Revenue Requirement model.

53/ Phase 1.A. Direct Testimony of Dr. Shucheng Liu on Behalf of the California Independent Operator, August 13, 2014, pages 14-15, available here: http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf.

54/ This report is available here: https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.

California was allowed to occur based on available information on physical limits of the transmission network, resulting in substantial exports on an annual basis.[55/] Yet the model is still forced to curtail renewables during the day: this study finds, in 2030, that curtailment ranges from 1.6% of hours in the year (33% RPS Scenario) up to 23% of hours in the year (50% RPS Large Solar Scenario).[56/]

Finally, preliminary results in an ongoing study by E3 and NREL for the Western Electricity Coordinating Council suggest that, when California has excess generation in the future, neighboring states also have excess generation, resulting in a limited ability to absorb California's excess energy. As a consequence, significant curtailment is still observed across the spring months in California, even when export from California is allowed.[57/]

In sum, recent studies indicate that assuming all curtailed energy in California can instead be exported is inappropriate, given findings that 1) there is no historical precedent to allow net exports from CAISO; and 2) even when export is allowed, substantial curtailment of RPS energy is still expected to occur, especially under scenarios with increased amounts of renewable penetration. Making such an assumption therefore overstates the avoided RPS value.

Some of the Status Quo parties (TASC, CalSEIA) claim policies such as default time-of-use rates and the promotion of electric vehicles will enable sufficient load shifting to fully utilize the output of RPS generators.[58/] Here, the Status Quo parties try to have it both ways; they argue that NEM should be considered independently of other policies (such as a higher RPS or ZNE) yet argue that some of these policies (such as TOU rates) will mitigate the costs of the NEM program. In addition, the Public Tool can model daytime EV charging's impact on

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55/ Table 25 of *Investigating a Higher RPS* demonstrates that under 33%, 40% and 50% RPS scenarios in 2030, exports are 2 to 4 times larger than the quantity of imports.

56/ From table 2 of *Investigating a Higher RPS*.

57/ This study models the 2024 TEPPC common case, which is the basis for CAISO's LTPP model as well as a High Renewables Case, also in 2024. The preliminary results are summarized here: https://www.wecc.biz/Administrative/E3_WECCFlex_TAS_Update_2015-08-10.pdf.

58/ CalSEIA pp.16 and SEIA/Vote Solar p. 41.

curtailment using the "more daytime charging" option for electric vehicles, which PG&E used in its independent case. Finally, in a number of the recent proceedings where an IOU has attempted to change its time-of-use periods to better match the net load curve and mitigate over-generation issues, a representative of Status Quo parties has stepped in to oppose such changes.[59/]

c. Vintaging

The Status Quo parties uniformly chose to "vintage" RPS curtailment and ELCC of NEM systems.[60/] This assumption means that two avoided cost inputs – curtailment hours and ELCC –are locked in for the entire life of a NEM generator at the amount observed in the year that the generator is installed. This option ignores the impacts that increasing penetration of renewable resources over time has on the level of curtailment (as discussed previously) and on ELCC.[61/] This is especially significant under 40% and 50% scenarios, where the RPS penetration can change significantly over the life of a NEM generator. Input assumptions used to calculate avoided cost are not "locked in" for 25 years for any other demand-side program, and this vintaging assumption is certainly inappropriate when these inputs are known to vary significantly in future years.

59/ However, as noted in PG&E's Proposal, while SEIA opposed PG&E proposal to adopt a 4-9:00 pm peak period for its new Time of Use Residential rates in PG&E's 2015 Rate Design Window Case, it eventually agreed to a settlement moving to those hours in that docket. See PG&E Proposal p. 48.

60/ According to the various parties' modeling inputs provided by CPUC and CalSEIA p. 27.

61/ See CPUC Energy Division's slides on ELCC decline and other "saturation" effects with increasing penetration of renewable energy in the 2/10/15 RPS Calculator Workshop here: http://www.cpuc.ca.gov/NR/rdonlyres/FF3EC176-3674-4DE8-ADB5-575322AA34AA/0/RPSCalcWkshp_0203ResourceValuation.pptx.

d. Integration Costs

For solar integration costs, the Status Quo parties relied upon E3's June 12, 2015 "Marginal Integration Cost Calculations" for solar of $2.38 per MWh for the 33% RPS.[62/] This figure is then used to estimate integration cost adders of $2.79 per MWh and $3.38 per MWh for the 40% RPS and 50% RPS cases, respectively. [Revenue Requirement: RR Inputs:G414-G416][63/] These figures are quite different among the parties.

PG&E simply notes that the E3 study referenced explicitly captures only the variable component of marginal integration cost, not the fixed component.[64/] These components are both required, pursuant to the methodology adopted in D.14-11-042. The Status Quo parties only include the variable component, and thus underestimate integration costs.

e. Avoided Transmission and Distribution Capacity Claims

SEIA/Vote Solar claim that solar avoids transmission and distribution upgrades; the utilities generally disagree.[65/] As the CPUC has found on multiple occasions, it is possible that DG systems interconnected to the distribution system can potentially defer distribution capacity expenditures, but this is time and location specific, not general.[66/] This potential is limited, primarily due to the lack of confluence of the following elements: (a) the need for distribution

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62/ This work, including the costs cited, is summarized in a May 29, 2015 filing by SCE located here: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/9ED56ECBA141C78188257E54007CE0F5/$FILE/R.13-12-010_2014%20LTPP-SCE%20Report%20on%20Renewable%20Integration%20Cost%20Study%20for%2033%20Perc%20RPS.pdf

63/ TASC Proposal Appendix A p. 14.

64/ Page 3 of the SCE filing described above states, "This report focuses only on the estimation of the variable component…"

65/ SEIA/Vote Solar pp. 23-26; PG&E pp. 74-76.

66/ See, for example, Decision 03-02-068, where the Commission concluded that although there is potential that distributed generation installed to serve an onsite use will also provide some distribution system benefit, unless it meets the four planning criteria described by SDG&E, such benefits will be incidental in nature. Similarly, see D.11-12-053 (PG&E's 2011 GRC, Phase 2), page 26 finding that "adding solar in one area does not reduce T&D needs in another area, and may not even help in the area where it is installed. If there is no need for T&D upgrades in an area, there are no such upgrades to avoid."

capacity expenditures; (b) the availability of DG in the correct amounts and in the right location; (c) the alignment between peak output time of the predominant form of DG, photovoltaic, and the peak demand time of the majority of PG&E distribution facilities; and (d) operating considerations associated with single large DG systems and aggregations of small systems. Moreover, at best, the influence of DG on capacity expenditures will likely be short-term deferrals of projects because the amount of DG on any one circuit or substation transformer is generally small. The avoided cost would typically only be the carrying cost of the avoided spend for the (likely short) period of deferral. It would not be the full cost of the asset unless the expected growth could indefinitely reduce the peak demand. The amount claimed for T&D deferral value is material.[67/]

PG&E, in partnership with Navigant Consulting, has performed a rigorous technical analysis to determine the impact that solar has on transmission and distribution capacity (see Appendix A). The study is designed to develop an objective, fact-based range of T&D costs and benefits resulting from the interconnection of higher levels of solar capacity on PG&E's electric grid. The study examines multiple solar penetration scenarios and separately attributes costs and benefits to retail and wholesale solar systems for the years 2015 through 2024. Many parties have stated that solar has general benefits to electric capacity which in turn reduces investments. As seen in the study, while solar can certainly reduce peak loads if it coincides with such a profile, the benefits would only be realized if (1) there is insufficient capacity in that area requiring a capacity investment; and (2) the duration of the local distribution peak does not

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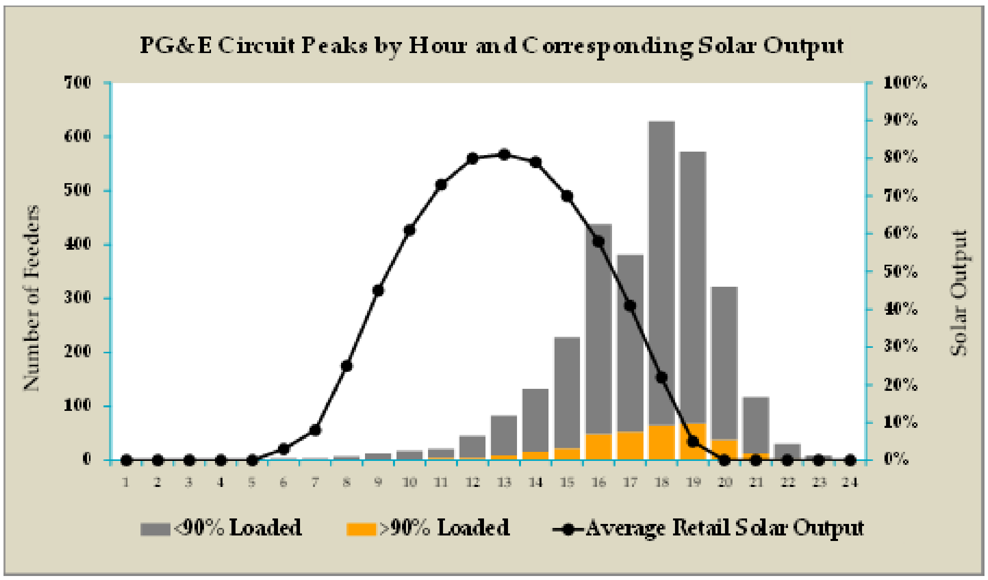
67/ If avoided Transmission costs are utilized, there is a dispute concerning what level of avoided costs are appropriate. SEIA adopts \$87/kW (p.24). This value is out of proportion with PG&E's calculation of Marginal Transmission Cost used in the last 2 General Rate Cases. Such an inflated value should not be used. See D.11-12-053, Appendix B, \$19.29/kW; See also, D.15-08-005, adopting the settlement in A.13-04-012, \$34.86/kW. Similarly, if avoided Distribution costs are utilized, the level of avoided costs must be determined. As shown on p. 75 of its filing, PG&E believes that that the net costs exceed any benefits of solar with respect to distribution costs. In addition, only the costs of deferrable investments should be considered "avoidable." This issue was also raised by TURN pp. 39 and 40.

surpass the duration of effective solar output. In the figure below, one can see how the majority of PG&E distribution circuits peak in the evening hours when solar output is low. Furthermore only a fraction of these circuits will be requiring capacity upgrades in the near future.

Figure 5: PG&E Circuit Peaks by Hour and Corresponding Solar Output



Source: Figure 1-2 in Navigant DGPV T&D Impact Study in Appendix A.

There are certainly instances in the system where solar coincides with the peak of a distribution circuit, but these localized benefits would only be realized from a small portion of the solar population. PG&E's Distribution Resources Plan has proposed methods of determining these localized benefits as well as demonstration projects that will seek to compensate the resources connected to such an area where they are providing effective capacity reduction. Any method of compensation through localized transmission and distribution benefits should be captured in this new process. An attempt to consider and account for T&D benefits in the NEM tariff could result in either double counting benefits and/or reducing the compensation to customers that are actually providing benefit. PG&E recommends the Commission not rely on the flawed avoided transmission cost number asserted by SEIA and Vote Solar based on an inappropriate regression analysis.[68/] Doing so would only increase costs to non-participating customers based on alleged benefits that do not really exist.

The report in Appendix A indicates that overall there will be a net cost[69/] due to solar rather than a net benefit. The table below shows the cost-benefit numbers calculated in the analysis. This table shows that while there could be some benefit and savings from solar, it is very minimal and only a fraction of the typical capacity budget required for growing peak demands.

Table 8: Retail Distribution Costs and Benefits, Mid-Retail, Mid-Wholesale Scenario

	DGPV Capacity (MW)			Net Retail Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	**559**	$7	$0	**$7**	$14	$8
2016	1,103	181	**1,284**	$12	$0	**$11**	$10	$6
2017	1,578	336	**1,915**	$22	$1	**$21**	$13	$8
2018	1,965	498	**2,463**	$28	$2	**$27**	$14	$8
2019	2,355	642	**2,997**	$45	$4	**$41**	$17	$10
2020	2,749	792	**3,541**	$58	$8	**$51**	$18	$11
2021	3,138	962	**4,100**	$74	$11	**$63**	$20	$11
2022	3,538	1,096	**4,635**	$90	$15	**$76**	$21	$12
2023	3,943	1,237	**5,180**	$109	$22	**$87**	$22	$13
2024	4,353	1,385	**5,738**	$125	$30	**$95**	$22	$13

Source: Table 1-6 in Navigant DGPV T&D Impact Study in Appendix A, p. 1-11.

The Public Tool default correctly excludes avoided transmission benefits for NEM. Recent and future bulk transmission projects are predominantly required for reasons other than meeting customer peak load growth. For example, changes in network topology, generator retirements, and the need to interconnect and deliver new grid-scale renewable resources are common drivers that would require transmission projects, regardless of load growth changes.

68/ Page 23 of Proposal of the SEIA/Vote Solar.

69/ The net cost shown in Appendix A is a conservative estimate. The actual cost associated with increasing amount of distributed PV could be higher.

In its E3 Reply Comments to 2013 Draft NEM Study[70/] E3, the creator of the Public Tool, said "in a review of the 2011/2012 and 2012/2013 CAISO Transmission Planning Process cycles, only 1 of 71 identified transmission upgrade projects planned through 2021 cited load growth as the reason for the upgrade. Moreover, bulk transmission marginal costs, in the years when bulk transmission was driven more by peak load growth, were generally quite low -- in the $10 to $15 per kW-year range. Because of the paucity of load-growth driven bulk transmission projects currently planned in California, and the historical low avoided cost value of such projects, we continue to assume an avoided cost of zero for bulk transmission."

Because load-growth driven bulk transmission projects currently planned in California are almost non-existent and, even when they did occur in the past the avoided cost value of such projects was low, SEIA and Vote Solar have resorted to an inappropriate technique—in this case, regression analysis—to invent a faux-factual and excessively high value for avoided cost benefits for NEM when there are none. SEIA and Vote Solar do a regression of the CAISO transmission revenue requirement forecast against the forecasted CAISO coincident peak. Even assuming 100% of transmission costs were a function of coincident peak, which they clearly are not, the near absence of growth related transmission costs in this analysis makes any outcome meaningless.

Even if we take the regression analysis of SEIA/Vote Solar at face value, the independent variable (MW) has a very high P-value. This implies a substantial amount of autocorrelation which typically means that there are other variables not captured by the regression equation that would impact the transmission revenue requirement. This confirms that there are a number of different things affecting transmission revenue requirement beyond just load growth. And load growth driven projects are almost non-existent according to the CAISO.

70/ http://www.cpuc.ca.gov/NR/rdonlyres/936C3EE8-20F3-43A1-9BCA-8F08A1E77BF1/0/E3ResponsetoCommentsonDraftReport.pdf, at p. 8.

f. Claims of Distribution Capital Expenditures Avoidable by DG

The Status Quo parties increase the percent of distribution capital expenditures deferrable by DG from 11% to 22%. This 11% factor represents the portion of distribution capital expenditures that are caused by existing load growth, while the Status Quo parties argue that this should be doubled to account for other investments also being deferrable. This arbitrary doubling is performed with absolutely no supporting evidence. As the Navigant study shows, it is likely that distributed PV will impose net costs on the distribution system, not benefits. The only concrete attempt by Status Quo parties to defend this change is to suggest that increased DG penetration could "potentially [reduce] the size of equipment being replaced."[71/] This proposed benefit is extremely unlikely to manifest itself in large savings, for three reasons. First, PG&E standard substation transformer sizes have an incremental difference of 15MVA. This large incremental difference will likely be too much for the chosen size to be affected by the impact of any capacity reductions by solar. Due to the load profile of solar, circuit loading can only be reduced to the highest post-sunset load. Second, only a portion of the cost of a distribution system upgrade depends on the size of the equipment being replaced. A 30MVA unit is only about $200 thousand cheaper than a 45MVA unit, which is negligible compared to the total project cost, typically around $5 million. While preventing or delaying an upgrade can produce savings involving the entire cost, downsizing an upgrade can only reduce this small portion of it. Third, solar PV may have a shorter effective useful life than most distribution equipment. If a transformer is downsized upon replacement due to high solar penetration at the time of the project, there is a risk that the asset would have to be replaced early if the solar system is not replaced at the end of their useful life. If this does happen, the replacement project cost will be far closer to the $5 million figure than the incremental cost of $200 thousand of installing a larger transformer. Given these three factors, it is extremely improbable that in aggregate solar

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71/ The Alliance for Solar Choice, p. 38.

will cause any significant net savings by reducing the required capacity of replacement distribution equipment.

g. Interconnection Cost Claims

The Status Quo parties "use the lowest reported [interconnection] costs (from SCE), assuming that the other utilities can achieve a similar level of cost efficiency in the interconnection process."[72/] PG&E has made tremendous strides to improve the efficiency of its interconnection process. PG&E's average time from interconnection request to approval is now 3 business days for projects that are 30 kW or smaller, all the while interconnecting more rooftop solar per month than any utility in the country. PG&E is proud of this record of efficiency, and continues to search for ways to drive costs out of this process. However, it is inappropriate to assume that PG&E's future costs will be the same as those used by Status Quo parties for SCE in the Public Tool. For one, it is very likely that the further adoption of distributed generation on the grid will result in less and less available capacity, increasing the need for system upgrades, and therefore increasing the cost of interconnection. Additionally, there are fundamental differences between PG&E's distribution system and SCE's system owing to significant differences in geography and population density that make system upgrades in PG&E's territory more expensive. Furthermore, following discussions with SCE, PG&E believes that the cost methodology used by SCE does not reflect a full accounting of interconnection costs. For example, PG&E included all costs for Interconnection Facilities and Distribution Upgrades incurred during the reporting period, whereas SCE only provided the costs of projects that reached completion. Therefore, PG&E's reported costs are an accurate portrayal of an efficient interconnection process under current requirements.

72/ SEIA/VoteSolar, p. A-5.

h. Utility Revenue Requirement Allocation Methodology

Various parties propose to change the tool's default revenue requirement allocation methodology from the default "Maintain current deviations" to "maintain current settlement rate relationships," arguing that the settlement results of recent GRC Phase 2 proceedings are more in line with the latter. TASC also claims that this has a significant impact on the results of the tool, increasing the RIM ratio from 0.5 to 0.82 and reducing total adoption from 3.5 million to 2.9 million installations.[73/] PG&E believes this result to be erroneous.

PG&E has conducted a similar sensitivity analysis, using the CPUC High Bookend with two tiered rates and existing NEM as a baseline. As seen in Table 9 below, while this change does drive slightly different results, they are not as dramatic as claimed by TASC, with the RIM test only increasing from 0.47 to 0.48. It is unclear how TASC arrived at such different results, as they were not explicit regarding what scenario was used as a baseline. However, given that they show the EPMC case with results far closer to the "maintain current rate relationships" case than the default case (which is a compromise between the two scenarios), PG&E suspects that TASC's "current deviations" scenario is using a different set of assumptions that the other two scenarios displayed.

Table 9: Comparisons Between the CPUC High Bookend Scenarios and TASC's Scenarios of Utility Revenue Requirement Allocation Methodology

Baseline Scenario	RRQ Allocation Scenario	RIM	TRC	Adoption in 2025 (MM Installs)
CPUC High Bookend, Two Tiers, NEM	EPMC	0.45	1.07	3.48
	Current Deviations (Base)	0.47	1.07	3.46
	Settlement Relationships Maintained	0.48	1.08	3.44
TASC/MRW Scenario	EPMC	0.78	1.05	3
	Current Deviations (Base)	0.5	0.98	3.5

73/ TASC Appendix A, p. 24.

Settlement Relationships Maintained	0.82	1.06	2.9

While it is reasonable to assume that over the 35 year timeline the Public Tool covers, the Commission will move closer to EPMC based allocations, this change does not appear to change the results of the tool enough to be a major issue.

2. Claims That Any Reform To NEM Will Cause Solar Adoption To Grind To A Halt Are Meritless

a. Claims That NEM Reform Will Cause a Solar "Train Wreck" Are At Odds With Reality.

CalSEIA and SEIA/Vote Solar argue that the solar market will be significantly disrupted by any change to existing net-energy metering policy, but these claims are largely unsupported by market analysis or guidance by leading industry participants. CalSEIA, for example, argued that policy changes would result in a "train wreck" that, combined with other recent developments such as a new residential rate structure, would "derail" the industry.[74/] Yet, this sentiment contrasts sharply with the announcements of leaders in the DG solar industry, such as SolarCity, which announced last July that residential rate policy reforms in California are going to actually *increase* their market and strengthen the industry: "We're excited about [residential rate tier compression] as it will increase our base. The challenge has never been the top tier. The challenge has always been the smaller homes or the homes that use less energy. **Now at our $0.15 offering, every customer will see a savings.**"[75/] (emphasis added.) In addition, in July of this year (after the final Residential Rate Reform decision) PG&E interconnected 5,943 new customers totaling 41 MW. This represents a 57% and 71% increase respectively over the interconnections in July 2014, clearly illustrating continued dramatic growth rather than any evidence of market disruption.[76/] The facts show that the solar market within California has

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74/ CalSEIA Proposal p. 6.

75/ Lyndon Rive. http://s.t.st/media/xtranscript/2015/Q3/13237877.pdf.

76/ In July 2014 3,785 customers interconnected totaling 24 MW.

reached a point of maturity and cost-effectiveness such that it no longer requires the massive subsidies associated with the current NEM tariff.

Another claim by CalSEIA and SEIA/Vote Solar is that the scheduled step-down of the federal Investment Tax Credit (ITC) will cause too much market disruption to achieve the competing legislative mandates of reducing the NEM cost-shift and the ensuring sustainable market growth for DG industries. But, again, market leaders like SunEdison and SolarCity have indicated that they do not anticipate that the federal policy change will disrupt their businesses. This February, for instance, SunEdison announced that it expects "strong growth" after the ITC step-down.[77/] In July, SolarCity made a more enduring public statement – saying that its "cost structure will allow [it] to thrive post-ITC reduction and generate $0.60 per Watt for equity value."[78/] This reality – that the industry expects to thrive even with a reduction in the Federal ITC – should not discount the very real possibility that the ITC could get extended after 2016.[79/] Overall, the arguments of market disruption by CalSEIA and SEIA/Vote Solar are overstated and strongly contradict the information solar industry participants are providing to the investing public. Arguments of a pending "train wreck" inaccurately characterize the current solar market, which has experienced astonishing levels of growth over the past decade and has matured to the point that it requires much less subsidization through NEM policy in California.

PG&E agrees that changes to California's NEM policy – in-line with the guidance and intent of AB 327 – would alter the economic value proposition of DG solar resources, but modifications can be made without risking the sustainable growth of these important low-carbon DG industries. When NEM policy was introduced in California in the mid-1990s, residential

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77/ "SunEdison expects strong growth post-ITC." February 24, 2015. http://www.pv-tech.org/news/sunedison_expects_strong_us_solar_growth_post_itc.

78/ http://s.t.st/media/xtranscript/2015/Q3/13237877.pdf.

79/ "Obama seeks to extend ITC permanently." PV Magazine. February 3, 2015. http://www.pv-magazine.com/news/details/beitrag/obama-seeks-to-extend-itc-permanently_100018023/#axzz3kR4gKoLt.

solar prices exceeded $\$14/W_{AC}$ or more than 4 times current prices.[80/] In 1997, the New York Times described NEM policy as an important tool to support the solar industry considering its status: "For years to come, solar cells will probably be too expensive to compete directly with electricity from the power grid."[81/] This is no longer the case. The market has grown rapidly – enabled by the ability to price solar systems below competing electricity rates – and the solar industry is now characterized by sophisticated, multi-billion dollar companies. In PG&E's service territory alone, more than 175,000 DG solar systems have been installed,[82/] but more importantly, the solar industry has also demonstrated consistent year-over-year growth in states that have much lower retail electricity rates than California. Since the current NEM compensation structure in most states is based on the underlying utility electric rate, this implies that the solar industry can experience strong growth at much lower levels of compensation. For instance, the solar industry has grown tremendously in Arizona, where retail electric rates set a much lower "ceiling" for solar pricing than in California (see Figure 4 on p. 5 of Appendix B). As a result, DG solar PPAs are priced much lower in Arizona ($0.08-$0.10/kWh) to provide a compelling value proposition to customers.[83/] The success of the solar industry in Arizona and other relatively low electricity price markets suggests that the solar industry can sustain a healthy market in California with an NEM structure that sets a price ceiling much lower than the full retail rate.

The profitability of DG solar sales in California is very high, and the implementation of a more tailored NEM policy design is overdue. Reports by Lawrence Berkeley National Laboratories, Bloomberg New Energy Finance, and the attached paper from Navigant Consulting

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80/ LBNL TTS. Page 13. http://emp.lbl.gov/sites/all/files/lbnl-6858e.pdf.

81/ NYTimes. http://www.nytimes.com/1997/08/16/business/but-us-solar-cell-makers-see-clouds-rolling-in-from-overseas.html.

82/ "How to Reduce Solar-Grid Interconnection Time by Nearly 80 Percent." Greentech Media. August 11, 2015. http://www.greentechmedia.com/articles/read/How-to-Reduce-Solar-Grid-Interconnection-Time-by-Nearly-80-Percent.

83/ See Navigant Distributed Solar Market Assessment Study, Appendix B, p. 5, Table 1.

(attached as Appendix B) have documented significant DG solar price disparities across states with Californians paying among the highest prices in the country. Navigant's analysis, in particular, illustrates a clear linkage between pricing and retail electricity rates (see Figure 4 of Appendix B), and documents how solar companies are pricing solar: they compete against retail electricity rates as opposed to one another, and the relatively high electricity rates in California have led to very profitable solar transactions. The market context of DG solar in 2015 is dramatically different than in 1997 (when NEM policy was first implemented) and smart modifications to NEM-based incentives will ensure continued and more sustainable growth of DG resources in California that achieve the guidance of AB327 and help mitigate the negative policy effects on non-participating ratepayers under the current policy approach.

The proposals by CalSEIA and SEIA/Vote Solar also erroneously describe the solar industry's current status through linkages to high-level industry growth considerations (S-curves). As noted in PG&E's filing on the Draft Tool, this flawed approach not only miscommunicates the DG solar industry's growth potential, but it also should not be used as a means to assess sustainable industry growth. CalSEIA suggests that with "less than 5% market penetration," [84/] the solar industry is in the slower adoption years of its natural growth cycle. However, CalSEIA does not mention that the position on an adoption curve should be a comparison of adoption among viable adopters, not the market as a whole. Studies suggest that solar is viable for a fraction of the total market due to structural considerations with buildings, shading, and other factors. And, the Public Tool assumes that only 35% of residential customers in California are capable of installing solar of rooftops;[85/] therefore, the market penetration among the market of viable adopters is already much higher than 5%. Considering this, as well as recent year-over-year growth rates exceeding 60% in residential markets, it is very likely that

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84/ Page 6, CALSEIA.

85/ E3 Public Tool, Advanced DER Inputs Tab.

the industry is in its "faster adoption" years, which would be characterized by rapid market growth at rates that cannot be sustained.

b. NEM Reform Will Support Sustainable Growth in the Solar Market

PG&E's filing and the Public Tool analysis all show that PG&E proposal will still leave customers with an incentive to install solar, with substantial bill savings opportunities.[86/] As shown in virtually all the tables above, including the bookends, the "more likely scenario," and PG&E's Independent Scenario, customers will still be able to achieve substantial savings under PG&E's Proposal. Indeed, in in most of these scenarios, customers will be able to achieve at least a 20% savings, even after adoption of PG&E's proposal.

Moreover, as discussed in more detail below, prices and margins are higher in California than other states. If the prices drop to more competitive levels in California, as they have in other states, additional growth opportunities are possible.

As the solar industry itself is explaining to its investors, there is room even with NEM reform for the industry to thrive and prosper. Similarly, analysis of the reasonable expected opportunities for customer savings show that there is vast opportunity for continued solar sales under PG&E's proposal.

3. Proposed Changes To The Adoption Forecast In The Public Tool Are Inaccurate

Parties opposed to any change in the current design of NEM argue that a variety of changes should be made to the adoption forecasts in the Public Tool. Each is misplaced for the reasons discussed below.

86/ PG&E Proposal pp. 10-12 and 43-49. In addition, PG&E's Proposal included at p. 10 text on specific bill savings opportunities for a representative residential customer. PG&E discovered an error in its original calculation. To fix this error, PG&E has corrected and updated the calculations underlying the bill impact estimate, which were set out in PG&E's Motion to File Correction filed on August 26th. In addition, customers can achieve additional savings by adjusting their usage behavior to reduce their system exports, reducing demand charges by smoothing out load patterns, and shifting on-peak usage to reduce TOU charges.

a. Solar Price Forecasts and Solar Vendor Margins

CalSEIA argued that the low solar price trajectory in the Public Tool is not realistic and that the Commission should not base its decision on a "wishful" price scenario, but few references support this claim.[87/] CalSEIA argues that, at a high-level, historical industry cost reductions have come from lower hardware (module) costs, and anticipated soft cost reductions in the future will occur at a slower rate. In contrast, PG&E argued that the low price projection is very feasible, citing several recent reports and public statements by industry leaders.[88/] For example, LBNL's recently released *Tracking the Sun VIII* report noted that: "…lower installed prices in other major international markets, as well as the wide diversity of observed prices within the United States, suggest that broader soft cost reductions are possible."[89/] CalSEIA does not acknowledge that profit margin, which can be quickly reduced under new policy, is itself a soft cost.[90/] CalSEIA also does not mention that prices in the Public Tool start at a high base due to the well-documented high-pricing in California that is tied to relatively high retail electricity rates (and that pricing is disconnected from costs).[91/] Further, CalSEIA makes no mention of PPA pricing which is the most important pricing consideration in the Public Tool since it is used to calculate DG solar deployments. As noted in PG&E's previous filing, the Public Tool adds significant costs to DG solar pricing scenarios in its calculation of PPA rates, which leads to a very feasible PPA pricing in the Tool's "low price" scenario.[92/]

87/ CalSEIA pp. 17-18.

88/ PG&E Proposal pp. 43-49 and 76-81.

89/ LBNL. "Tracking the Sun VIII." August 2015. http://emp.lbl.gov/sites/all/files/lbnl-188238_0.pdf.

90/ U.S. Department of Energy (LBNL/NREL). "Photovoltaic System Pricing Trends." September 22, 2014. Page 24. http://www.nrel.gov/docs/fy14osti/62558.pdf.

91/ Despite having the largest market in the United States, California consistently reports the among the highest DG solar prices in the country. See page 29 of LBNL's *Tracking the Sun VIII*. http://emp.lbl.gov/sites/all/files/lbnl-188238_0.pdf.

92/ PG&E Proposal pp. 46-48, 76-81.

What CalSEIA describes as a “wishful” pricing scenario has already been achieved in other states. PPA rates in states like Arizona and Colorado are significantly lower than in California, and analysis by Bloomberg New Energy Finance,[93/] as well as a study completed by Navigant on behalf of PG&E, which is included as Attachment B, indicates significantly lower system pricing in markets where the utility avoided rate is lower than California. This pricing dynamic is documented in other studies, including an NREL report that was cited in the Public Tool, which notes that solar pricing is tied to customers' monthly bill savings (which is based on competing retail electricity rates).[94/] In California's DG solar market, there is significant room for these margins (and other soft costs) to drop rapidly.

93/ Bloomberg Energy Finance. “H1 2015 US Residential PV PPA Survey.” April 6, 2015.

94/ Sigrin and Drury. "Economic Returns Required by Households to Adopt Rooftop Photovoltaics." 2014. https://www.aaai.org/ocs/index.php/FSS/FSS14/paper/viewFile/9222/9123.

Table 10: Comparison of Reported Residential PPA Rates ($/kWh) in 2014 by State

State	Quoted Residential PPA Rate[95/]	Marginal, Highest Tier Electricity Rate	Average Retail Electricity Rate[96/]
Arizona	$0.08	$0.17[97/]	$0.12
California/PG&E	$0.15	$0.34[98/]	$0.19[99/]
Hawaii	$0.19	$0.41[100/]	$0.36
Massachusetts	$0.10	$0.23[101/]	$0.16
New Jersey	$0.12	$0.20[102/]	$0.15
New York	$0.15	$0.20[103/]	$0.19

95/ Residential PPA rates quoted by leading TPO providers (with escalator tied to inflation, at 2-3% per year).

96/ EIA Average Retail Electricity Rates, October 2014.

97/ Arizona Public Service, Rate E-12. (www.aps.com/library/rates/e-12.pdf)

98/ Pacific Gas & Electric Company, Rate E-1, Zone X. (www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-1.pdf)

99/ PG&E October–December, 2014 Residential Retail Rates. (www.pge.com/tariffs/electric.shtml)

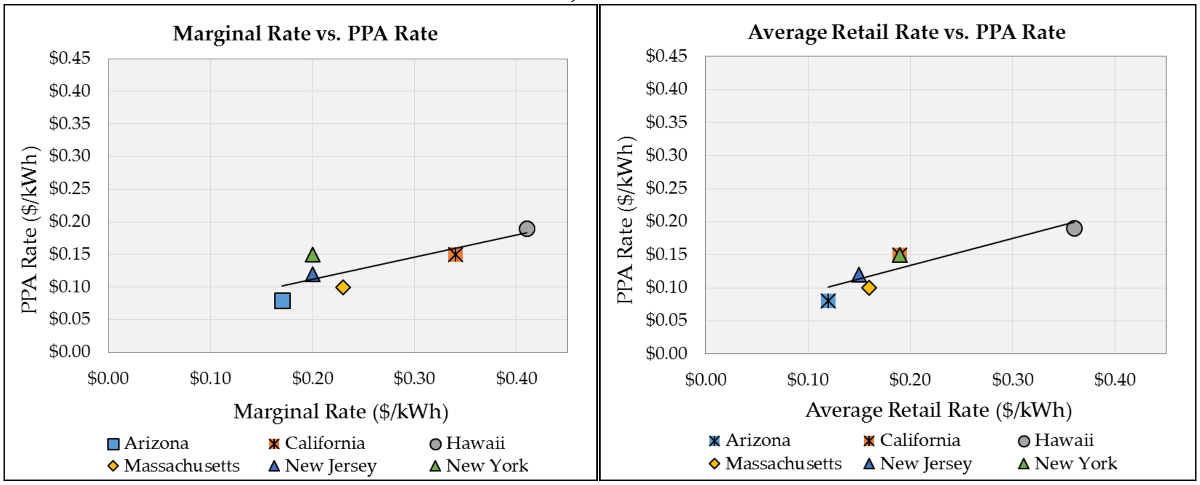
100/ Hawaiian Electric Company, Rate R. Includes Energy Cost Adjustment charge of $0.055210/kWh. (www.heco.com/vcmcontent/StaticFiles/FileScan/PDF/EnergyServices/Tarrifs/HECO/EFFRATESOCT2013.pdf)

101/ Eversource Energy, Rate R-1. (www.eversource.com/Content/docs/default-source/rates-tariffs/190.pdf?sfvrsn=6)

102/ Public Service Gas & Electric, Rate RS. (www.pseg.com/info/environment/ev/rlm-rs_rates.jsp)

103/ Consolidated Edison, Rate EL-1 and SC-1, Rate I. (https://apps1.coned.com/csol/msc_cc.asp, www.coned.com/documents/elecPSC10/SCs.pdf)

Figure 6: Comparisons of Solar Price Forecasts and Solar Vendor Margins in AZ, CA, HI, MA, NJ and NY



Source: Navigant analysis, 2015, Attachment B, p. 5, Figure 4.

b. Adoption Model Tab and DER Sizing Relative to Load

CalSEIA and SEIA/Vote Solar argue that the adoption calculations in the Public Tool are wrong, and they make changes that significantly impact the Tool's outputs. In particular, they argue that the "model inaccurately estimates that a majority of customers will install systems that offset 100% of load."[104/] They are the only parties to make a number of changes to the adoption modeling in the Public Tool.

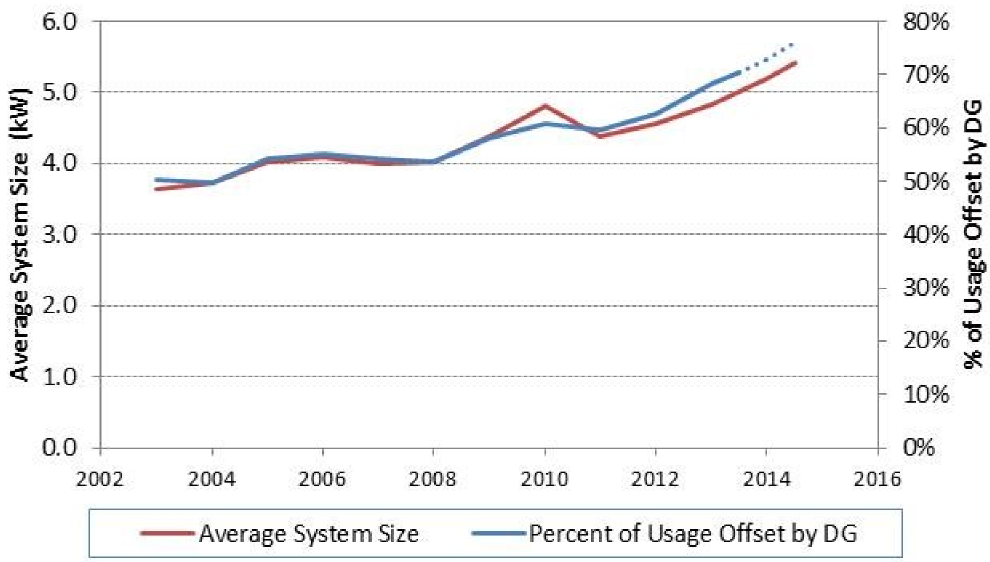
PG&E does not agree with these parties' modification to the Public Tool's system sizing algorithm or the supporting rationale, which is unsubstantiated. CalSEIA argued that customers "tend to be conservative…[and] most will choose the smaller system"; "many customers are limited by available roof space"; "solar customers on TOU rates do not size their systems to offset 100% of onsite load"; and, "minimum bills eliminate the benefits of sizing a system beyond a certain percentage of annual consumption." SEIA/Vote Solar argued that non-economic factors such as "building orientation, shading, [and] aesthetics…will tend to reduce system sizes." [105/] Yet, no data or studies are provided to support the magnitude of these claims.

104/ CalSEIA pp. 30-31; SEIA/Vote Solar pp. 14-15.

105/ Ibid.

In contrast, available market data supports the default settings in the Public Tool. As illustrated below, historical data of DG solar deployments in PG&E's service territory show increasing solar system sizes in California and, most importantly, the share of a participating customer's electricity usage offset by DG solar has been consistently increasing. PG&E expects that the historical trend of having high-shares of electricity usage offset by DG solar will continue as a result of a number of factors, including: increases to solar module efficiencies (greater power generation from smaller areas), reductions in solar costs (enabling customers to buy larger systems for lower expense), the adoption of energy efficiency advancements (reducing load), and, most importantly, the implementation of residential rate reform flattening tiered rates. Therefore, PG&E strongly recommends that all parties adhere to the Public Tool's default adoption algorithm.

Figure 7: Average System Size (kW) and % of Usage Offset by DG from 2003 - 2015



Source: PG&E Analysis of all residential NEM customers with at least 1 year of interval data post-DG adoption as of May 31, 2015. For customers adopting after May 31, 2014, % offset estimated assuming the same pre-DG usage as 2014 adopters with sufficient data.

The Status Quo parties' changes to the Public Tool's adoption algorithm have a significant impact on the model's outputs. The parties did not recognize that E3 had already included modifications to the Final Tool to increase small and medium systems (relative to load), which the Status Quo parties then take much further.

Prior to releasing the final Public Tool, E3 wrote (Q&A doc.):

> "These small, medium, and large size breakdowns are computed relative to a customer's annual load (small is 33% of annual gross usage, medium is 66% of annual gross usage, and large is 100% of annual gross usage)."[106/]

> "For DER size selection in the adoption logic, switched from using a highest NPV approach to a weighted average between NPV and B-C ratio approach. The draft version of the public tool used only NPV to select the optimal system size for a given participant, while **the final version uses NPV and B/C ratio, which leads the model to select a larger percentage of small and medium systems. This decreases total MW adoptions and increases 'With DER' cost of service recovery because customers install smaller systems."**[107/]

Page 14-15 of the SEIA/Vote Solar proposal stated:

> "…the unmodified Public Tool adopts Large systems, offsetting 100% of the customer's load, to an extent that differs significantly from the historical distribution of system sizes…the adoption model should start from an allocation of system sizes based on past experience, which reflects not only economics but also the other constraints on system sizing. As a result, we have modified the adoption model to limit the system size adopted for a particular bin of similarly-situated customers to the historical system size for that bin, **using E3's data through 2012 on the actual system size for each bin**." (Emphasis added.)

In other words, the Status Quo parties retained general proportionality between small and large systems from 2012 to 2025. Fixing system sizing at 2012 levels ignores the major changes in price signals and DG economics and results in understating adoption, cost-shifts, and the percentage of cost of service paid by NEM successor tariff customers. Only two out of the sixteen parties of this proceeding modified the Public Tool's default setting for the adoption

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106/ E3 Public Tool Question & Answer Document, p. 4. http://www.cpuc.ca.gov/NR/rdonlyres/BC2D0D02-D5F5-42C4-8E7A-A4AAF172C7E0/0/Public_Tool_QA_5282015.pdf.

107/ E3 Public Tool Q&A Document August 18 Version, p. 58, http://www.cpuc.ca.gov/NR/rdonlyres/DFBEB5B7-B28D-4A2F-BDBC-41B5E5A0BDEF/0/PublicToolQA8182015.pdf.

algorithm, which E3 had already reviewed and refined during the development of a Final Tool, and PG&E recommends consistent usage of this important aspect of the Public Tool across all party proposals.

c. Rate Escalation

Various parties (SEIA-Vote Solar, CalSEIA, TASC, Sierra Club) incorrectly reduce the Public Tool adoption model's assumption on customers expectation of rate increases from 5% to 3%, which significantly reduces predicted adoption. While PG&E agrees that 3% may be a more reasonable assumption than 5% in the abstract, changing the expected rate escalation is inappropriate at this stage in the modeling. The Public Tool's adoption algorithm was tuned to benefit-cost ratios which included a 5% escalator, so using a lower rate escalation factor without recalibration results in an under prediction of adoption. E3, the developers of the Public Tool, agrees with this assessment of the implications of changing this input. Per the Energy Division's public Q&A document on the Public Tool, "the tool was calibrated using both the assumed 5% escalation rate along with the adoption parameters and any change to these inputs means that the user is implying a fundamental change in the relationship for how many customers might adopt solar for a given economic proposition. This assumption change is akin to reducing the adoption parameters (which were historically calibrated). The implication of changing this input from 5% to 3% is that the tool will forecast less adoptions which will in turn decrease the cost-shift. We could have calibrated the tool using an assumed utility rate increase of 3% annually, but then the adoption parameters would have been higher."[108/]

This would be an appropriate change if historic adopters expected significantly higher utility rate increases than future adopters. However, this is not what the Status Quo parties argue. They provide substantial evidence that the rate increases predicted by the model and

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108/ E3 Public Q&A Tool Document August 18 Version, p. 51, http://www.cpuc.ca.gov/NR/rdonlyres/DFBEB5B7-B28D-4A2F-BDBC-41B5E5A0BDEF/0/PublicToolQA8182015.pdf.

escalators used by leading solar companies are well in line with the rate increases experienced by customers over the last decade.[109/] Therefore, this recommended change to the model is simply incorrect and the resulting low adoption forecasts of the Status Quo parties should be disregarded by the Commission.

d. Non-Residential Rates

Several parties noticed that some of the default non-residential rates do not precisely match actual utility rates, and changed the offending rates to equal what they felt were more representative levels.[110/] This change is unnecessary, as the rates in the Public Tool were intended to represent a spectrum of rates. Each customer class in the tool (residential, small commercial, medium commercial, etc.) may have several rate tariffs available, and certain rate tariffs have multiple options within them. To simplify the modelling, E3 "seeded the model with rates that were representative of the many different rate schedules that may be represented by one customer segment in the Public Tool."[111/] PG&E finds this to be a reasonable modeling compromise.

e. Other Rate Changes

In its independent scenario, CalSEIA assumes that residential rates have a $10/month fixed charge, PG&E's and SDG&E's CARE discounts are reduced to 32.5%, and that PG&E's small commercial customers pay a demand charge, believing that the CPUC will eventually approve such changes.[112/] Again, CalSEIA tries to have it both ways. It argues that the NEM Successor Tariff should be designed independently of certain policies (50% RPS, ZNE, fixed charges, demand charges), but assumes other policies are enacted that reduce cost shifts and participant value, so as to better make the case for no changes to existing net metering. In effect,

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109/ SEIA/Vote Solar, p. A-1.

110/ CalSEIA p. 30, TASC p. 35.

111/ E3 Public Q&A Tool Document August 18 Version, p. 51.

112/ CalSEIA, pp. 29-30.

CalSEIA includes changes to rates that have similar impacts to PG&E's own NEM successor tariff proposal (non-volumetric rate components for residential and small commercial customers) in its own default case to argue against any changes to NEM taking place. CalSEIA even acknowledges that it would strongly oppose both the residential fixed charge and small commercial demand charge in CPUC proceedings.[113/] CalSEIA's independent scenario should be completely disregarded.

4. If the Commission Considers The Societal Cost Test, It Should Not Adopt The Values Proposed By Sierra Club.

All parties representing the interests of solar vendors relied on a paper written by Alison Seel (of Sierra Club) and Tom Beach (author of SEIA/Vote Solar Proposal) to derive values for various societal benefits. The paper presents claimed values for non-energy benefits of distributed generation.[114/] As discussed above, PG&E recommends the Commission not rely on the long list of societal benefits asserted by Sierra Club and the Status Quo parties. However, if the Commission wishes to consider the topic, this section explains why the values claimed by Sierra Club are not accurate. PG&E is still waiting on a data request response from the Sierra Club, and may have to modify or add to this critique if the data request reveals information that was unclear in the original paper.

The Sierra Club Report did not provide persuasive evidence of a link between reduction in energy use, reduction in energy generation, reduction in concentrations of particulate matter from stationary sources, and reduction in societal health care costs in California. While PG&E recognizes that its generating portfolio does produce criteria air pollutant emissions, it is important to understand these emissions in the broader context of air pollution sources in California. A major focus of the California Air Resources Board and local California air quality

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113/ CalSEIA opposed adoption of any fixed charge in the Residential Rate OIR, and D.15-07-001 denied fixed charges for residential customers for at least the next several years. It is expected that the Status Quo parties will continue to oppose all such charges.

114/ Attachment 2 of Sierra Club proposal, Prepared by Alison Seel (Sierra Club) and Tom Beach (Crossborder Energy and Co-Author of SEIA/Vote Solar proposal).

management districts for over a decade has been reduction in particulate matter from the transportation sector, especially diesel trucks. According to the California Air Resources Board's latest emissions inventory, transportation related pollution sources accounted for 85 tons of particulate matter (PM 2.5) emissions statewide in 2012, compared to about 5 tons of emissions from electric utilities.[115/]

The Federal Clean Air Act and California Clean Air Act regulate the emission of criteria air pollutants in order to meet health-based air quality standards. The cost of meeting these regulations through emissions offsets is already captured in the Public Tool and is the appropriate means to capture any benefits from air pollution reductions associated with NEM technologies. Adding additional air quality benefits that cannot be accurately linked to emissions from electric generation may significantly overestimate the air quality benefits associated with NEM technologies.

a. Claimed Values For The Cost Of Carbon

The authors suggest adding "social carbon costs" that range from $14-$109 to the "carbon costs" already accounted for in the NEM Public Tool, citing estimates developed by an Interagency Working Group established by Executive Order to evaluate Federal GHG regulations.[116/] This is inappropriate for several reasons.

Carbon costs are already included in the tool. The State of California has established GHG emission-reduction targets through AB 32 and California's cap and trade system is a best attempt at establishing a societal "willingness to pay" across a range of potential GHG emission reduction strategies. This helps ensure the state's GHG goals are achieved at lowest cost as required by AB 32.

115/ California Air Resources Board Emissions Inventory Data. http://www.arb.ca.gov/ei/emissiondata.htm Accessed August 27, 2015.

116/ https://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

As of August 2015, average California GHG allowances are trading at about $13 per ton, comparable to the 'base' carbon cost scenario in the NEM Public Tool.[117/] As modeled by the Public Tool[118/], and as happens in the energy marketplace, these carbon costs are and accounted for in estimates of the avoided costs associated with retail solar exports.

NEM generation, when offsetting carbon-emitting generation, reduces demand for cap and trade allowances but might not actually reduce state-wide GHG emissions because the electric utility sector is covered under California's cap-and-trade program. Total emissions from sources covered by California's cap-and-trade program are determined by ARB when it determines the "cap" or "budget" levels. Given a binding[119/] cap and-trade program, activities that reduce emissions at covered sources act to help the state meet that cap, but do not reduce emissions beyond those levels. As such, there would be no additional GHG reductions to value using a social cost of carbon. The value from avoiding GHG allowance costs is fully reflective of the AB 32 GHG benefits of NEM generation solar in California.[120/]

In fact, the ARB has a program called Voluntary Renewable Electricity (VRE) set-aside which is designed to provide the opportunity for voluntary production of renewable energy to reduce GHG emissions through retirement of emission allowances. The ARB guidance on this program specifically states that allowance "Retirement allows voluntary purchasers of renewable electricity to credibly claim a reduction in GHG emissions. Without retirement, these compliance instruments would be used by other entities with compliance obligations <u>resulting in</u>

117/ California Cap-and-Trade Program Summary of Auction Settlement Prices and Results http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

118/ See Cell "C 13" in "Key Driver Inputs" tab of Public Tool.

119/ While state GHG policy after 2020 is not settled, recent goals set by Governor Brown suggest a binding cap beyond 2020.

120/ This is analogous to the interactions of overlapping state and federal GHG policy in Stavins and Goulder (2010), where California's cap-and-trade program acts as the overarching regulation and DG solar the nested GHG reduction program: http://www.nber.org/papers/w16123.pdf.

no GHG emission reductions from the use of voluntary renewable electricity."[121/] [emphasis added]. To date, this program has retired only ~84,000 emission allowances for 2013, due to the participation of seven entities.[122/]

In addition to starting with a high carbon value, the paper inflates this value over time using the U.S. Department of Labor's CPI inflation calculator. PG&E notes that the paper ignores the more relevant forecast of carbon costs available from the EPA, which is lower than the authors' calculated forecast using the CPI calculator. The authors clearly knew about the EPA costs, because they relied on that source support a statement about the lack of precise information available. By 2025, the difference is significant, as can be seen in Table 11, below.

Table 11: Comparison of Seel/Beach Carbon Cost Forecast and EPA Carbon Cost forecast.

	2007	2015	2020	2025
SC/C				
3% averag3	$36.00	$41.43	$52.88	$67.49
3% 95th Percentile	$105.00	$120.85	$154.24	$196.85
EPA				
3% average		$40.00	$47.00	$51.00
3% 95th Percentile		$117.00	$140.00	$150.00
SC/C Overestimate				
3% average		$1.43	$5.88	$16.49
3% 95th Percentile		$3.85	$14.24	$46.85

121/ Page 1 of ARB Guidance for Regulation Sections 95831(b)(6) and 95841.1 located here: http://www.arb.ca.gov/cc/capandtrade/guidance/chapter7.pdf.

122/ http://www.arb.ca.gov/cc/capandtrade/renewable/vreparticipants.htm.

b. The Claimed Cost of Criteria Pollutants

In Sierra Club's NEM proposal, the authors suggest adding a social cost of particulate matter of $184 per lb. and, which is a weighted average of 'benefit per ton' estimates developed by the US EPA as part of the Federal Clean Power Plan[123/] which range from 165,000-450,000 dollars per short ton.[124/] They also suggest adding a societal cost of $24 per pound for nitrous oxides.

It is not appropriate to assume that a single emission factor from a fossil generator can capture the avoided marginal emissions associated with added retail PV. The composition of resources that will be generating coincident with retail PV is getting cleaner and cleaner. This will overstate the avoided emissions beyond the method used in the Public Tool.

Another reason that Sierra Club's suggestion that the CPUC consider quantified additional benefits from air quality and GHG emissions reductions using the Public Tool is flawed is that the underlying heat rates assumed in the Public Tool are too high and not in line with other modeling been done in the state. The air quality and GHG emissions reductions modeled in the Public Tool are based on heat rates for a marginal generator that are unreasonably high (~5,000 Btu/kWh) during the middle of the day in shoulder months starting in 2015. As PG&E's generation sources become cleaner over the next ten years, consistent with meeting the Renewable Portfolio Standard, the marginal generator offset by a retail solar system is likely to have on average, a very low heat rate, as retail solar generates power at the same time as utility-scale solar. This can be inferred from PG&E's discussion of energy price forecasts on pages 30-33 of this document, where PG&E's estimate of mid-day energy prices is far lower than those in the Public Tool, despite similar gas prices.

123/ USEPA Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf. http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants#CPP-final.

124/ Sierra Club NEM Proposal, Attachment A, p. 6.

c. Claimed Values For Reliability And Resiliency

In its proposal, Sierra Club advances values for "Reliability and Resiliency," which it claims are provided by distributed generation.[125/] However, the vast majority of solar systems immediately shut down during a system event such as a line fault or rapid frequency shift. When these events occur it takes some time for the units to come back online. During this time the grid serves the load that was previously served by the DG and can cause a ripple effect to outage conditions. This effect gets worse as DG penetration gets higher, and it is already being seen in Hawaii. As a result, there is no such reliability benefit for other utility customers.

Moreover, in most cases, unless the system is installed with a battery backup that can operate independently from the grid, it does not provide any reliability benefits even for the customer that installs it. The Sierra Club study falsely claims that all DG projects provide such benefits. Thus, calculated values for "Reliability and Resiliency" are meaningless.

Even if one were to accept the argument made for these benefits, the calculated value ($0.022/kWh) would be wrong by an order of magnitude. The Sierra Club assumes 79% of DG customers are residential, whereas of July 31, 2015, 96% of PG&E's DG customers were residential. Additionally, the Sierra Club assumes that the average non-residential system is a mere 16 kW, compared to the actual average system size of 100 kW for PG&E. Simply correcting for these factors while using the same formulas reduces this value from $0.022/kWh to $0.0016/kWh, or by 92%.

d. Claimed Land Use Benefits

In Sierra Club's Paper, the authors recommend that the Public Tool use an input that would value avoided land coverage associated with retail PV at a price that reflects typical California prices for agricultural land. Sierra Club suggested a value of $7,200 per acre reflective of "farm real estate" per survey conducted by the US Department of Agriculture which

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125/ Pages 9-11 of Sierra Club Attachment 2.

includes irrigated cropland.[126/] This is totally inappropriate given that there is marginal land available in the state that is not viable for agriculture or other productive uses that can be used for solar production.

e. Claimed Values For Local Economic Benefits

Seel and Beach include local economic benefits of $0.03/kWh for all solar installations, claiming that the cost premium of DG (residential in particular) relative to utility scale solar that is spent locally represents a societal benefit. The soft costs included as a benefit in the resulting SCT include customer acquisition (including marketing); installation labor; permitting, inspection and interconnection; and permit fees. This assumes that all soft costs are a net societal benefit and displace absolutely no spending in other areas of California's economy. Were this true, there would be no reason for California to work towards reducing solar soft costs except to the degree that would allow increased deployments. Since interconnection-related costs are also included, this seems to indicate that the effort PG&E has spent achieving record interconnection speeds was all for naught, and is a wash from the perspective of the societal cost test.

Even assuming that local soft costs represent a true societal benefit, the Sierra Club does not appear to conduct this analysis properly and therefore exaggerates the societal benefits of DG. It uses clearly outdated soft costs from 2013 (which have declined in the meantime and are predicted to decline further in the Public Tool) on benefits side of the SCT, while the soft costs on the costs side of the SCT decline. This has the effect of dramatically inflating this benefit, even if one were to accept the underlying premise that solar soft costs do not displace spending (at all) elsewhere in the economy.

In addition, the economic impacts are distorted. The local economic benefits are not appropriately modified by what costs are avoided by solar companies. For example, any permits

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126/ http://www.nass.usda.gov/Statistics_by_State/California/Publications/Other_Files/201209lndvlscshrnts.pdf.

fees are included as a benefit, but, in contrast, the fact that solar generation is exempt from property taxes is not included as a loss for the local economy.

5. Solar Customers Will Not Be Paying Their Fair Share of the Cost of Service Without NEM Reform

As many of the pro-reform parties have noted, volumetric rates (per kWh) are not an adequate reflection of cost of service for the infrastructure investments made to serve customers. This problem is exacerbated by the addition of solar generation at a site where NEM customers that take serve on these volumetric rates can currently avoid paying for the infrastructure required to serve them. Customers choosing to install solar should face rates that properly reflect cost of service so that they can make an efficient economic choice among service alternatives like distributed generation. PG&E's proposed demand change structure provides just such a framework. Moreover, under a demand charge structure such as the one proposed by PG&E customers can still choose to reduce their PG&E charges by managing their load in conjunction with their solar output. In this way, customers only pay for the capacity that they use and can still manage their load.

PG&E's proposal included cost of service results shown in the Public Tool, which demonstrates that solar customers are not paying a fair share of their costs of service.[127/] Table 2 in the Proposal showed that under two cases in the Public Tool, the Status Quo proposal resulted in NEM customers only paying 32-33% of their cost of service. SEIA, CalSEIA and TASC have already indicated that they think cost of service is a very relevant metric, stating in earlier comments in this docket that, "The Public Tool should include a cost-of-service study to inform discussion regarding the extent to which net energy metering (NEM) customers cover the costs the utilities incur to serve them."[128/] Unless NEM is reformed, solar customers will not be paying a fair share of the costs of service to them.

127/ PG&E Proposal Tables 1 and 2, Introduction p. ii and p. 4.

128/ Joint Comments by SEIA, CalSEIA and TASC on the Public Tool Workshop dated Oct. 1, 2014, p. 1.

D. The Proposals For NEM Reform Submitted By TURN, ORA, NRDC, SCE, SDG&E and Energy Division All Show Promise

TURN, ORA, NRDC, SCE, SDG&E and Energy Division all made proposals that will reduce the rate impact on non-participating customers. Some do so through a demand charge, some through capacity-based charge, some through a feed-in tariff. Most of these reform parties also proposed reduced export compensation. All of these are a step forward. All will help the move to a more sustainable solar future. While PG&E believes that its proposal is the best designed to meet the needs of the state going forward, each of these other proposals also has promise for doing similarly.

In particular, PG&E notes that the TURN proposal for a feed-in tariff provides a transparent method for compensating customers who install renewable generation. SDG&E also includes a feed in tariff as an alternative choice for customers. Customers taking service under a feed in tariff first pay for their energy usage under an applicable rate that applies to all of their usage. All of the exports are credited at a rate that is transparent, and easily compared to the actual value of the energy generated, even where (as is the case with both TURN and SDG&E) that compensation is higher than the value. PG&E notes that TURN proposes that the compensation for generation be applied as a credit to customers' utility bills. Because this is similar to the way exports today are compensated under the existing NEM program, this feature may address any suggestion that the compensation for generation might be taxable.

E. The Proposals For Change To Related NEM Subsidies Also Show Promise

1. VNEM and NEMA

VNEM – a number of parties argue that Virtual Net Energy Metering (VNEM) should be extended or expanded. As noted in its proposal, PG&E strongly opposes the expansion of VNEM "as it has been demonstrated to significantly increase cost shifting to non-adopting customers."[129/] VNEM expansion is nothing more than an expansion of freewheeling service, a

129/ PG&E Proposal, p. 29.

concept that is not supported by the legislature, has always been limited by the CPUC, and should not be extended or expanded. VNEM more than any other form of retail net metering increases the likelihood that participants will not contribute to services that are provided. In addition VNEM, as it exists today (including NEMA) imposes other costs on nonparticipants, with increased interconnection costs and increased billing costs. As the CPUC explained in D.11-07-031, which rejected proposals to expand Virtual Net Metering broadly:

> PG&E claims that the concept of transferring kWh credits beyond the service delivery point would be a significant departure from Commission precedent. For example, PG&E asserts that in D.03-02-068, the Commission considered and rejected "distribution only wheeling." (See PG&E, 12/6/10 at 5.) In addition, PG&E cites several instances where the legislature has provided customers the opportunity to generate power at a given location on the utility grid and to have it consumed at another location on the grid. In all those instances, PG&E asserts that customers have been required to cover the costs of transmitting and distributing the power and they receive only a generation credit at the point of consumption. According to PG&E, the Staff Proposal to allow NEM credits across [Service Delivery Points] would encourage other utility customer groups, such as agricultural and local government customers, to push for other retail wheeling schemes, and this could substantially increase the costs borne by other customers….
> **PG&E raises valid concerns over wheeling and the use of the transmission and distribution grid.**

D.11-07-031, pp. 11-12 (emphasis added). That decision went on to generally limit VNEM to customers served by a single service delivery point. D.11-07-031, p. 16.

VNEM allows customers who rely on the use of the distribution and transmission network to avoid paying any costs associated with that service. The underlying costs do not disappear, but the revenues from the participating customers do. It is not a sustainable or equitable energy policy to force non-participating customers to pay another customer's cost of service.

VNEM, "to the extent that it allows generation in one location to serve remote load" is "essentially *de facto* Direct Access, in which the energy supplier gets freewheeling service."[130/]

130/ PG&E Proposal, p. 30.

As noted in PG&E's proposal, "even moving power from a generator to load located nearby involves wheeling, and both FERC and the CPUC have rejected proposals for providing such service without paying for all the necessary elements of such service, including transmission costs."[131/]

The increased interconnection and billing costs shifted to non-participating customers offer another strong reason to not continue or expand VNEM and NEMA as they exist today. In the case of NEMA interconnection costs, "generation sized to aggregate accounts can be located at remove locations where the distribution system was sized to a modest pumping load. It simply is not equipped to accept the exports that NEMA can cause."[132/] From a billing perspective, the monthly reallocation of credits significantly increases billing costs.

For the reasons stated above PG&E continues to oppose requests for VNEM-type tariffs with few exceptions. One exception is using a form of virtual net metering to provide additional support for multifamily low-income housing developments (i.e., MASH participants). The other exception is to allow agricultural customers aggregation under modifications necessary to ensure against the cost shift so prevalent in the NEMA tariff.

Aggregation: PG&E recognizes the importance of account aggregation necessary to engage our agricultural customers in renewable generation; PG&E agrees that aggregation can be continued and included in the successor tariff so long as measures are taken to minimize rate impacts. See discussion in PG&E's proposal.

2. Interconnection Cost Responsibility

Interconnection costs: Any tariff can only be considered sustainable in the long run where participating customers pay for the costs their system imposes. PG&E proposed moving closer to the cost of service, by looking at recorded interconnection costs to propose \$100 for systems under 30 kW and \$1600 for systems over 30 kW. These fees would be used to offset the

131/ See CPUC and FERC authorities cited in PG&E's proposal at p. 30.

132/ PG&E Proposal, p. 31, footnote 42.

cost of processing and reviewing applications, performing necessary studies, and commissioning and inspecting the meter configuration. Many parties simply proposed that such services continue to be provided for free, offering little or no explanation why it would be inappropriate to move closer to covering the costs of service from participating customers.

3. Public Purpose Program Charges

The one slight change from business as usual for the parties advocating no reform was a suggestion by some of them that after a non-specified period of time, some non-bypassable charges might be paid on some of the generated electricity. This is too little, too late to make any real difference, and PG&E has largely ignored this in our analysis because the proposals are vague and their impact is small. However, we do note that PG&E is aligned with those Status Quo parties who support change on this one point, although PG&E would end the exemption from non-bypassable charges on exports to the grid from start of the NEM successor tariff. In addition, PG&E is aligned with the Status Quo parties on treatment of generation used to meet the customer's own load. PG&E also would continue to allow full retail credit for this on-site generation usage.

4. Monthly vs. Annual True Ups

Most parties did not address this issue. Those who did provided a variety of methods to address the annual true-up. PG&E can support any proposal that is simple for customers to understand, and that also simplifies billing and accounting. However, PG&E continues to believe that monthly true-ups would be the optimal choice for simplicity of design, better customer understanding, and ease of implementation.

5. Projects Larger Than One MW

PG&E supports expansion of the size cap for customers prepared to pay for costs currently paid by nonparticipating customers, namely all interconnections costs, including system upgrades. The Legislature has indicated support for this through recent legislation creating exceptions to the one MW NEM size cap for the California Department of Corrections and Rehabilitation, as well as explicit language in AB 327 that generally supports PG&E's position.

III. DISCUSSION OF THE PROPOSALS FOR NEM FOR DISADVANTAGED COMMUNITIES

A. Introduction

As directed by AB 327, several parties submitted proposals with specific alternatives to the standard NEM successor tariff aimed at promoting growth of renewable distributed generation among residential customers within disadvantaged communities. Parties' proposals for disadvantaged communities fall into several camps:

- Some parties simply support the IREC proposal.
- Some parties support the Energy Division proposal to expand VNEM to all residential customers in disadvantaged communities while some parties suggest further expansions to VNEM as part of the disadvantaged communities' proposal.
- Some parties essentially support the Energy Division option of supplementing the existing low income solar incentive programs.
- Grid Alternatives supports continuation of full retail net metering for a defined subset of customers in disadvantaged communities combined with additional incentive enhancements.
- CEJA proposes a complex program available to all residential customers in disadvantaged communities.
- SDG&E and SCE offer thoughtful proposals to boost low-income solar adoption within disadvantaged communities.

PG&E comments on parties' proposals in the order laid out above.

In addition to evaluating whether other parties' proposals for disadvantaged communities would overcome existing barriers to solar adoption by low income customers, PG&E relied on several principles to determine whether or not a program would be feasible, efficient and transparent. The first principle PG&E relied upon is that full retail net metering should no longer apply for any customer moving forward. The second principle is that Virtual Net Metering should not continue outside of two limited exceptions: for MASH customers with on-site generation serving customers at a single service delivery point and for agricultural customers in NEM aggregation with adequate protection for nonparticipating customers. This principle is derived from the fact that VNEM has been shown to significantly increase cost shifting as participating customers benefit from free-wheeling of energy and the associated costs with providing this service fall on non-participating customers. The third principle concerns "hidden subsidies." PG&E believes that if it is necessary to use a subsidy to increase solar adoption for low-income customers within disadvantaged communities then this subsidy should be transparent. Programs that propose to maintain full retail net metering for all or a subset of customers within disadvantaged communities will be using a hidden subsidy and should therefore not be considered. The fourth principle requires that the program be as cost-effective as possible. Some proposed programs put forth would require a great deal of administrative burden that would undoubtedly raise the overall cost of meeting the legislature's goals to increase solar adoption within disadvantaged communities. Other proposals put forward would significantly increase the overall cost of the program to non-participating customers by increasing the extent of the NEM subsidy by expanding virtual NEM. These principles are discussed in PG&E's original proposal and used to evaluate specific party proposals below.

B. IREC's Proposal

IREC's proposal, dubbed CleanCARE, uses a novel approach to incent adoption among CARE customers within disadvantaged communities. CleanCARE seeks to use part of the CARE subsidy to pay for solar projects. CARE customers would then be put on a standard residential rate and receive an allotment of credits for a portion of this solar generation. There remain too many issues and outstanding questions that prevent PG&E from supporting CleanCARE or from believing this approach would be the most effective way to accelerate adoption for CARE customers within disadvantaged communities. These issues are further detailed below.

First, IREC is incorrect to assume it's complicated proposal can be accomplished with no additional funding required. A key part of the IREC proposal is the method to ensure a CARE customer opting into the CleanCARE plan save at least the same amount or more on the CleanCARE rate as they would on the CARE rate. In order to ensure these savings, IREC has proposed two billing options:

In option 1 "Each month, the program administrator would evaluate the CleanCARE participant queue customer by customer. If the program administrator determines that Customer 1 would save money on CleanCARE that month based on how much energy that customer actually used in that month, then Customer 1 would participate in CleanCARE, i.e., pay for service at standard residential rates and receive the appropriate number of kWh bill credits. If not, that customer would receive service at CARE rates."[133/]

Constantly switching many customers' bills from one rate (CleanCARE) to another (CARE) and back again on a monthly basis will be very costly. Such a rate structure would be vastly different from anything that currently exists. As a result, dual billing calculations (one for CARE, one for SolarCARE + solar credits) would need to take place on a monthly basis to ensure the customer received the correct (lower) bill each month. Such a billing scheme will necessarily incur higher costs to develop the systems needed. [134/] The communications between

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133/ IREC CleanCARE Proposal, p. 8.

134/ A high level internal estimate undertaken by PG&E projects the cost to set up such a dual billing scheme would be roughly $2-4 million dollars with further ongoing annual costs to run and maintain such a system still to be determined. The following areas that would need to be addressed to set up this billing scheme include: PG&E billing process would need to be modified to calculate customers with equivalent Non-CARE rate; PG&E billing process would need to be changed to wait for the CleanCARE credit before billing customers; PG&E billing process would need to be modified to cancel non-Care bill and recalculate customers with CARE rate if CleanCARE bill is higher than CARE Bill; Revenue Reporting/Allocation would need to be modified for reporting CARE shortfall; new financial reports will likely be need to be developed to capture CleanCARE program credits.

the utility issuing the customer bills and the program administrator determining which bill to present to the customer would also require additional funding to ensure data/billing privacy and accuracy.[135/] The administrative cost of $0.03/kWh used in IREC's analysis would likely be too small to cover the additional burdens placed on the billing and communications systems to manage such a scheme, especially considering that this amount would need to be split between the utility and third party administrator, if this program, as proposed, were to be managed by a third party. The necessity of increasing the administrative portion would therefore undoubtedly damage the value proposition IREC presents for eligible customers under the "high" solar cost, and very likely even under the lower, Re-MAT based solar cost.[136/]

In option 2, a customer would sign up for CleanCARE for the next year but "on a monthly basis, the program administrator would evaluate the CleanCARE customer's bill impacts under traditional CARE rates and the CleanCARE paradigm. If necessary to meet the requisite CARE bill reduction in a given month, and to account for seasonal variations of solar output over the course of the year, the program administrator would apply additional kWh bill credits to that customer's bill for the month in order to bring her bill down to the level it would have been under the CARE program. The program administrator would set-aside a modest 'bank' of kWh bill credits (e.g., five percent of the total CleanCARE generation) for this purpose, to be included as an administrative expense of the program (i.e., covered by the $0.03 per kWh assumed administrative cost)."[137/]

135/ Multiple interfaces would need to be developed for exchanging data between PG&E and the external third party administrator, who it is assumed would manage enrollment, conduct the necessary evaluation to determine the monthly credit and communicate to PG&E which rate to bill the customer. These communication interfaces have been included in the high level estimate discussed in the preceding citation.

136/ For instance, in IREC's analysis a Tier 2 customer in PG&E territory using 400 kWh per month would only see additional bill savings of $1.40 under the IREC proposal using what is very likely too small of an Administration charge. An increase of just a cent on the administrative charge would mean this customer would be better off on the CARE rate.

137/ IREC CleanCARE Proposal, p. 8.

While option 2 does not also require switching back and forth between rates on a monthly basis as the customer would remain on CleanCARE for the entire year, it still presents issues that would likely incur higher costs than IREC appears to assume. A "modest bank" of credits may very well need to be larger than 5% of the total CleanCARE generation to ensure customers are no worse off than they would be under CARE for every month of the year. This would likely mean that the administrative and/or solar cost would need to be increased and require additional funding outside of the CARE subsidy amount that would purportedly cover all costs associated with CleanCARE. As illustrated above, relatively small changes to the administrative portion of the "solar cost" presented in IREC's analysis would remove the value proposition under the high cost of solar scenario as well as for lower usage CARE customers under the low cost solar scenario.

Second, there are questions about the benefits of the rate structure proposed. IREC asserts that moving customers to "regular" residential retail rates will help push customers toward more energy efficiency and/or conservation efforts due to the higher variable cost of electricity. This assertion is doubtful if these customers are assured that their bill would revert to CARE rates if this would be the lower of the two rate options for a given month. This may even create the perverse incentive to use more electricity as the customer would know that they are assured to have a lower variable cost (CARE rate) if they consumed more electricity than their bill credit allotments would offset. If the CleanCARE customer elected to partake in the program for a year with the understanding that there is the chance for their bill to be higher due to the higher variable cost component, this might sufficiently incent those to undertake measures IREC mentions as ancillary benefits. However, without this "risk" put into the equation, it is doubtful that customers would be likely to undertake measures to save more energy, and could conversely be incented to use more energy knowing full well that the CleanCARE program offers a stop-gap to ensure they won't be forced to pay any more than what the CARE rate or a bank of "credits" allow for.

Third, PG&E opposes IREC's proposal that even if the full retail rate credit does not continue for ordinary NEM customers, "IREC suggests that full retail rate bill credits are appropriate for customers participating in CleanCARE."[138/] IREC suggests "addressing concerns raised in the past by utilities and other parties about the costs of 'wheeling' power to offsite customers" by "suggesting a cost adder to the all-in cost of CleanCARE solar generation to reflect distribution costs."[139/]

However, even with a distribution cost adder, there would still be a suite of costs that wouldn't be collected under CleanCARE VNEM + distribution and administration costs model. The costs that would continue to be shifted to other customers include all other retail rate components including: transmission, transmission rate adjustments, reliability services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, DWR Bond, and the New System Generation Charge. Further, the rate would also shift costs to other customers associated with providing renewable power. For example, the Green Tariff Shared Renewables program identified the following costs that needed to be paid by participating customers in order to keep other customers indifferent: PCIA, RIC, RA, CAISO charges, and WREGIS. IREC goes on to note that "although the Commission has approved a separate bill credit paradigm for the Green Tariff Shared Renewables (GTSR) program for off-site shared generation, it results in participants paying a premium above their normal rates to participate and therefore is not appropriate for CleanCARE, where participants must save as much as, if not more than, they would have under the CARE rate discount."[140/] PG&E's proposed Solar CARE program would install community solar installations meeting 100% of a selection of CARE customers' annual usage in disadvantaged communities at no premium to participating CARE customers. Solar CARE, like GTSR, would include all of the

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138/ IREC CleanCARE Proposal, p. 6.

139/ Ibid, p. 6.

140/ Ibid, p. 6.

applicable costs designed to keep ratepayers indifferent. Solar CARE would still require a small, yet transparent, subsidization. However, PG&E believes this subsidy amount would be considerably smaller than that required by CleanCARE and therefore is a better program to achieve growth of solar adoption in disadvantaged communities.

C. Proposals To Expand of Virtual Net Metering for all Residential customers in Disadvantaged Communities

Several parties supported some version of Energy Division's first option, known as "Neighborhood Virtual Net Energy Metering (Neighborhood VNM)." Energy Division's proposal would not be limited to low-income customers within disadvantaged communities, but rather to all residential customers in CalEnviroScreen-designated disadvantaged communities. As noted in its proposal and above, PG&E strongly opposes the expansion of Virtual Net Energy metering However, PG&E noted two exceptions to this: "one to support the continuation of such programs for the MASH program for our low income customers and the other to support our agricultural customers."[141/] It is unnecessary and duplicative to expand VNM to non-CARE customers, who can take advantage of the successor tariff without this added incentive." In addition to the successor tariff, non-CARE customers residing in multi-family housing or areas unsuitable to physically install solar on the premise throughout PG&E's territory will be able to sign up for community solar via the two options provided under the Green Tariff Shared Renewables program. Low-income and CARE customers will also have the ability to participate in either the MASH or SASH programs that have proven successful in reaching part of this market. To assist CARE customers in disadvantaged communities who may not have the ability to take advantage of incentive funding under MASH or SASH, PG&E believes that its proposed Solar CARE program would provide the most cost-effective way to address the barriers that prevent these customers from taking advantage of the standard NEM successor tariff, GTSR or MASH/SASH funding to go solar.

141/ PG&E Proposal, p. 29.

SEIA and Vote Solar proposed an expanded version of Energy Division's option 1 (Neighborhood VNM). The proposal is a significant expansion on Energy Division's proposal as it would: remove the Single Service Delivery point requirement for VNEM customers; require that the site for any generating unit only have "parasitic load in order to qualify;" and allocate credits based on a customer's retail rate for non-CARE customers while giving CARE customers a "credit multiplier." For the reasons stated above in the discussion of Energy Division's Neighborhood VNM, PG&E opposes expanding virtual net metering outside of two limited exceptions (MASH and NEMA). PG&E strongly opposes the expanded SEIA/Vote Solar "Disadvantaged Communities VNEM" proposal which would significantly exacerbate the cost shifting issues highlighted as unnecessary in Energy Division's proposal. This is detailed below.

1. Proposal To Remove Single Service Delivery Point Requirement

SEIA/Vote Solar propose that "the Commission should consider removing the single-Service Delivery Point barrier for all multi-tenant properties in this proceeding, and would definitely need to remove it for Disadvantaged Communities VNEM."[142/] PG&E continues to disagree with this notion as it would significantly increase cost-shifting and is not necessary to achieve the legislative intent. The single Service Delivery Point (SDP) is required to ensure that the additional costs that would be required to deliver solar power from the site of the generation unit to customer load do not fall on non-participating customers. As PG&E has previously argued when the Commission contemplated expanding VNEM in the past, the demonstrated cost shift from conventional NEM would be "accentuated if an expanded VNM arrangement is implemented beyond the SDP, as such an arrangement unambiguously requires PG&E's T&D assets to move the power from the point of production to the point(s) of consumption. Through avoiding charges/and or receiving bill credits at the full retail rate, customers on such an expanded VNM would receive benefits that are disproportionate to the costs incurred. In effect,

142/ SEIA/Vote Solar Proposal, footnote 74 on page 53.

all accounts in the expanded VNM development…would have their T&D charges for solar power deliveries subsidized by other customers."[143/]

2. Proposal That Any Generating Unit Only Needs "Parasitic Load In Order To Qualify"

SEIA/Vote Solar's assertion that "the host customer need only have parasitic load in order to qualify"[144/] is another example of how costs/ benefits from its proposed program are not taken into account. By claiming that "there is no difference between *most* or *virtually all* of the project's generation benefitting offtakers on other sites,"[145/] SEIA/Vote Solar are completely ignoring transmission and distribution costs associated with moving electricity from the generating site to the benefitting customer, who, under their proposed siting criteria, could be hundreds of miles away.

3. Proposal For Full Retail Credit for Non-CARE customers and CARE Customers to Receive a Credit Multiplier

By proposing "that Disadvantaged Communities VNEM credits be allocated on a volumetric basis based on the participant's retail rate"[146/] the SEIA/ Vote Solar proposal is a significant expansion from the Energy Division Neighborhood VNM proposal. The Neighborhood VNM proposal would at least restrict "the underlying compensation structure for the energy generated by the renewable DG system" to "the same compensation structure that the Commission adopts for the standard NEM successor tariff/contract."[147/] PG&E believes that full retail net metering is inappropriate and should not be continued in any capacity as a result of this proceeding.

143/ PG&E Comments on Phase 1 Issues in the CSI/DG OIR, Filed May 6, 2010. Page 3.

144/ SEIA/Vote Solar Proposal, p. 55.

145/ Ibid.

146/ SEIA/Vote Solar proposal, p. 55.

147/ Energy Division Staff proposal, p. 2-12.

The SEIA/Vote Solar proposal would greatly increase the overall cost needed to incent CARE customers to participate in its program and increase adoption. Since CARE customers pay a lower volumetric retail rate, which "makes them less attractive prospective customers for developers to target, and making the economics of participating less attractive for those customers" the SEIA/ Vote Solar proposal would allow CARE customers to "receive a credit multiplier on their VNEM bill that corrects for the size of the average CARE subsidy."[148/] Under this proposal, not only would non-CARE customers need to pay for the CARE subsidy but would also be responsible for the cost-shift associated with crediting Disadvantaged Communities VNEM CARE customers at a higher rate than either what they currently pay for electricity via their CARE retail rates or whatever compensation structure the Commission decides is appropriate for NEM customers moving forward.

D. Proposals To Enhance Incentives For Low-Income Residential Customers In Disadvantaged Communities

Energy Division's second proposal states that "all customers in disadvantaged communities would participate in the same standard NEM successor tariff/ contract that is adopted by the Commission…but that an upfront financial incentive would be provided to low-income customers in CalEnviroScreen-disadvantaged communities for the installation of solar PV systems on their properties. Essentially, Staff proposes that the SASH and MASH programs be provided with additional funding to expand the number of systems they install, but to focus the installation of these additional systems in CalEnviroScreen-designated disadvantaged communities only."[149/]

Several parties supported Energy Division's second proposal or said they could support it with further study/minor modifications. These parties include Southern California Edison (SCE), The Utility Reform Network (TURN) and the Office or Ratepayer Advocates (ORA).

148/ SEIA-Vote Solar proposal, p. 55.

149/ Energy Division Proposal, p. 2-16.

PG&E asserts that its proposed Solar CARE program would better address some of the barriers that would remain under Energy Division's second proposal at a lower cost to all customers.

1. Merits of Energy Division's Incentive Enhancement Proposal

Energy Division's Incentive Enhancement proposal restricts eligibility to low-income customers, and also includes a cap. Both elements are appropriate. PG&E agrees with Staff that low income customers are the group that faces the greatest number of barriers and therefore requires additional incentives in order to adopt solar in disadvantaged communities. This is in contrast to Staff's VNEM proposal that would inappropriately and inefficiently be available to all residential customers within disadvantaged communities. Moreover, unlike Energy Division's first proposal that would be an uncapped expansion of VNEM for all residential customers in disadvantaged communities and therefore greatly increase the resulting cost shift, the Incentive Enhancement program would be capped at an amount appropriately determined at a later date. Energy Division states the total program costs would "likely have a minimal impact on the overall costs to non-participating customers."[150/] This represents a much more prudent manner in which to meet the mandate from AB 327 while ensuring non-participating customers do not have to subsidize a much more costly rate design.

MASH and SASH are also proven programs that have successfully contributed to the installation of over 45 MW statewide. MASH in PG&E territory alone has helped incent the installation of over 13 MW.[151/] Staff's recommendation of allocating additional funding to the existing MASH and SASH program administrators would allow the successes these programs have seen thus far can be continued and will help with low-income customer solar adoption in disadvantaged communities. However, as discussed in PG&E's proposal, the Solar CARE

150/ Ibid, p. 2-19.

151/ Installed and pending capacity as of August 19, 2015. https://www.californiasolarstatistics.ca.gov/reports/agency_stats/.

proposal is more cost-effective and addresses the other barriers to program participation in disadvantaged communities,

2. Barriers that Remain under Staff's Incentive Enhancement Proposal

Many existing barriers to adoption, however, are not met with Energy Division's Incentive Enhancement Program. Energy Division mentions that this program would not overcome some specific barriers to adoption faced by low-income residents in disadvantaged communities. Specifically, the Property Ownership and Property Structure barriers would not be met by providing additional funding to MASH and SASH. For multi-family dwelling residents, Energy Division mentions in its proposal that "the decision to go solar would be the property owner's and not the tenant's."[152/]

Another barrier concerns property structure, which Energy Division admits "the upfront incentive program does not directly address."[153/] Similar to this barrier are others not mentioned directly by Energy Division that also hamper an upfront incentive program of this type, such as technical constraints related to shading, roof orientation, and insolation.

In order to overcome these barriers while also offering minimal impact on non-participating customers, PG&E believes its proposed Solar CARE program would be better suited to give low income customers in disadvantaged communities the ability to go solar.

E. Grid Alternatives Proposal

Grid Alternatives' proposal, defined as "full retail NEM + funding/program support" combines elements of Energy Division's two proposals.

As previously noted above and in PG&E's proposal, PG&E does not support the continuation of full retail net metering for any customer as an outcome of the NEM Successor Tariff proceeding. Under PG&E's proposal, all customers would receive the generation component of their rate as a credit for electricity exported to the grid to help offset a portion of

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152/ Ibid, p. 2-18.

153/ Ibid.

their monthly PG&E bill. It is neither necessary nor efficient to create a retail NEM carve-out of this nature to help with the adoption of solar in disadvantaged communities given that alternatives, such as PG&E's proposed Solar CARE program, addresses barriers to adoption without doing so.

The second element of Grid Alternative's proposal is very much like Energy Division's second option and has been discussed above.

F. CEJA's Proposal

The California Environmental Justice Association (CEJA) has put forth a complex proposal called Environmental Justice Net Energy Metering (EJ-NEM) that is made up of a number of elements that make it complex from an operational perspective and highly inefficient from a cost/benefit perspective when compared to other proposals aimed at boosting solar adoption for residential customers in disadvantaged communities. This is especially true when comparing CEJA's proposal to PG&E's Solar CARE proposal that would more efficiently and more transparently meet the goals of AB 327.

The proposed "compensation rate" is complex and probably unfeasible. CEJA states that its "EJ-NEM bill compensation rate is central to the proposal."[154/] The complexity and foreseeable issues that would come to bear due to this compensation rate render the proposal unsuitable for effectively and efficiently incenting solar adoption by low-income customers within disadvantaged communities.

EJ-NEM proposes the utility credits a participating customer's account not by what is determined to be a cost-effective and fair amount by the Commission in this proceeding nor by a customer's retail rate, but rather through a fixed amount over a 20-year period.[155/] This fixed bill

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154/ CEJA proposal, p. 8.

155/ CEJA proposal, p. 5.

credit amount is to be "based upon the projected long term average retail rate of residential customers."[156/]

Although CEJA envisions that the bill credit amount would be updated each year for new participants, participating customers would be locked into a bill credit amount that "will be set annually by a tariff for projects installed in that year and memorialized in a standard contract."[157/]

There are a number of issues with this central tenet of CEJA's proposal. First, coming up with a 20 year retail rate forecast to determine a long term credit amount is particularly worrisome as such a long term forecast is bound to be incorrect after only a few years. PG&E does not forecast the average retail rate for residential customers projected out for 20 years. Such a forecast would be impossible to develop with sufficient confidence and therefore highly inappropriate to base a long term crediting scheme on.

Second, locking this amount into an inflexible 20-year contract would likely present a large cost shift to non-adopting customers responsible for subsidizing adopting customers' guaranteed bill credits. CEJA gives its purported rationale for establishing its program as a contract as opposed to a tariff by stating: "contracts are not subject to changing rates due to changing regulations."[158/] Establishing such a contract may be favorable to the adopting customer who would be guaranteed a specified credit amount for 20 years but would be likely very bad for ratepayers footing the bill. The inherent uncertain nature of forecasts, especially long term forecasts, due to the fact that things change over time is precisely the reason why rates are established as tariffs subject to change at the Commission's discretion. Despite any large changes in costs, rates, and/or regulations, CEJA's proposed contract would mean adopting

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156/ CEJA proposal, p. 5.

157/ CEJA proposal, p. 11.

158/ Ibid.

customers (and ratepayers subsidizing this program) would be locked in for an extended period of time without a means to adjust the program.

Third, stated reasoning for guaranteeing a higher than retail rate bill credit for low-income customers because "low CARE rates give low bill credits under NEM" and that "by providing a bill credit rate that is based on the average cost of service and therefore more closely approximates the benefit that most other customers who participate in net metering receive"[159/] would no longer be the case under PG&E's NEM successor tariff. Under PG&E's proposal, no customer will receive full retail credit for energy exported. All customers (CARE and non-CARE) would receive the same export credit (the generation component of their retail rate) to help offset their monthly bill.

In addition, the proposal inappropriately focuses on *all* residential customers within Disadvantaged Communities. As noted in PG&E's proposal and several times throughout comments on other parties' proposals on increasing adoption within disadvantaged communities, PG&E believes it is the low-income customer segment of these areas which requires attention to boost solar adoption and that the non low-income segment of the market, within or outside of disadvantaged communities, has numerous opportunities to adopt solar such as through the standard NEM successor tariff or through the Green Tariff Shared Renewables program. Unfortunately, CEJA's proposal would be for all residential customers residing in the top 25% of CalEnviroScreen determined disadvantaged communities. When attempting to justify its program for all customers CEJA by and large discusses only the barriers faced by low-income customers, stating that "EJ-NEM is primarily designed to address financial barriers because financial barriers are the most significant barrier to renewable DG adoption in Disadvantaged Communities."[160/] A program that would be "funded by a state subsidy or the general rate

159/ CEJA proposal, p. 6.

160/ CEJA proposal, p. 7.

recovery"[161/] should not be eligible to customers who do not face the same barriers as low-income customers and therefore can adopt solar through other means if desired.

Furthermore, the CEJA proposal pushes for VNEM expansion. CEJA proposes that its complex contract structure would be available to all residential customers within disadvantaged communities through VNEM. PG&E has insisted at numerous points in this proceeding and throughout its comments that VNEM should be discontinued except in very limited circumstances due to the freewheeling and other costs these customers do not pay and therefore shift to non-adopting customers. A program such as the one CEJA is offering would not fall within the limited circumstances as it is open to all residential customers and there is no service delivery point requirement to allocate credits virtually.[162/]

G. SDG&E and SCE proposals

SDG&E developed a well thought out proposal that would see the utility lease roof space on multi-family housing units and schools within disadvantaged communities for the placement of solar PV. Bill credits consistent with the exported energy rate set forth in SDG&E's Sun Credits NEM successor tariff option would then be allocated to local low income-qualified residents within the same census tract. PG&E agrees with SDG&E that this program would successfully address barriers to solar adoption faced by low-income customers in disadvantaged communities and looks forward to learning more about this proposed program.

161/ CEJA proposal, p. 2.

162/ There are many additional open questions and issues about this proposal. They include the following: What would happen if the customer moves to a different location in less than 20 years? CEJA proposes that this fixed rate include both an ordinary rate increase estimate, as well as an additional amount "to account for future uncertain rate increases." What initial rate escalation figure would need to be adopted in setting this credit guarantee? What mechanism would be needed to ensure that this cash payment be spent on renewable distributed generation, as opposed to other kinds of expenditures, particularly since CEJA proposes that customers be permitted to sell or transfer the expected payment stream? Would the proposal only be offered to low income customers, or would it be made available to all 500,000 customers in disadvantaged communities? Is there any cap on participation levels in the proposal? What is the estimated cost of this proposal to non-participants?

SCE proposed two options to help solar adoption within disadvantaged communities in its service territory. The first option is a version of the enhanced incentives proposal put forth by Energy Division that would offer a two tiered incentive structure depending on how much of the energy is used to offset tenants' usage versus property owner usage. SCE's second option is a community solar program similar in nature to PG&E's disadvantaged communities proposal. As mentioned in its proposal and throughout these comments, PG&E believes community solar through its proposed Solar CARE program will best address barriers faced by low-income customers within disadvantaged communities while also doing so in an efficient and transparent manner and should therefore be pursued in this proceeding.

IV. CONCLUSION

For the reasons set forth above, PG&E requests that the Commission reject the proposals for no change to current NEM design. It submits that its proposal is the best alternative presented to date. It looks forward to working with all the parties as the Commission moves forward with this important work.

Respectfully submitted,

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September 1, 2015

Appendix A: Navigant Distributed Solar Photovoltaic Transmission and Distribution Impact Analysis

NAVIGANT

Distributed Generation Solar Photovoltaic Transmission & Distribution Impact Analysis

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1. Executive Summary

Navigant conducted this Distributed Generation Photovoltaic (DGPV) Transmission and Distribution (T&D) Impact Study as a research effort on behalf of Pacific Gas and Electric Company (PG&E). The study is designed to develop an objective, fact-based range of T&D costs and benefits resulting from the interconnection of higher levels of DGPV capacity on PG&E's electric grid. The study examines multiple DGPV penetration scenarios (low, mid and high penetration) and separately attributes costs and benefits to retail and wholesale DGPV systems for the years 2015 through 2024.

Overview

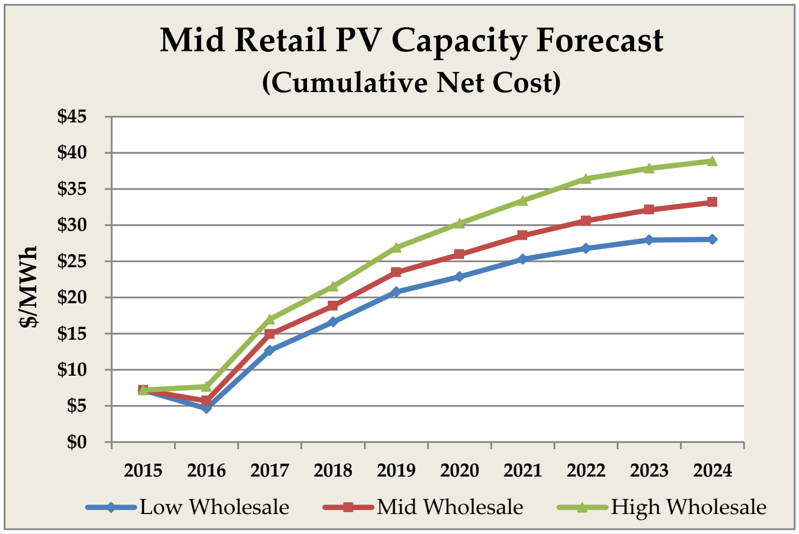
The study provides a current alternative to prior statewide estimates of DGPV marginal net value by using an approach that more accurately reflects costs and benefits for PG&E's grid. Prior studies completed by E3 for California investor-owned utilities predicted positive net benefits from DGPV for each utility. Navigant's study for PG&E, described herein, demonstrates positive net cost for all DGPV scenarios evaluated. The primary reason for the contrasting results is the much greater level of rigor in our study. For PG&E, Navigant conducted detailed simulation studies of the distribution and transmission system, including evaluation of over 3000 individual feeders. The E3 study, while conceptually sound, applied high-level estimates for integration costs and benefits, using avoided cost forecasts that do not fully account for differences in the time of feeder and transmission system peaks that often occur during evening hours when solar output is low. The avoided cost forecast also does not differentiate between unavoidable investments such as those required for reliability or condition-based replacements.

Figure 1-1 illustrates cumulative net transmission and distribution costs attributable to retail DGPV over the 10-year study horizon for the mid retail DGPV scenario, with wholesale DGPV at low, mid and high penetration levels.[1] The cumulative net cost for the mid scenario is $33/MWh, of which about one-half is for transmission-related upgrades. For the low and high wholesale DGPV forecast scenarios for the retail mid-case, the marginal net costs for transmission and distribution system upgrades attributable to behind-the-meter PV in 2024 are estimated to be $28/MWh and $39/MWh, respectively.

Should policies, operations, planning, price signals, and technologies align to optimize deployment of DGPV in the long-term, the benefits are likely to be higher and costs are likely to be lower, but the costs will still likely outweigh the benefits. Navigant explored a minimum cost scenario ("Targeted DGPV") where the underlying assumption is that customers are somehow incented to locate DGPV in areas where impacts are lower, or technology solutions such as energy storage can be used to mitigate impacts. For the minimum cost case, marginal net cost to interconnect DGPV is estimated to be $5/MWh or lower for all years of the study.

[1] Values in Figure 1-1 exclude wholesale DGPV interconnection costs.

Figure 1-1. Retail DGPV Net T&D Costs



Source: Navigant Analysis

Methodology

The study methodology is based on the California Energy Commission's (CEC's) Analytical Framework, but with additional detail and analytical rigor.[2] The primary assumptions about upgrade costs, triggers, and values were informed by PG&E and are more conservative (i.e., result in lower costs) in nature than those used in a previous CEC study for Southern California Edison (SCE).[3] The following steps highlight the overarching methodology applied by the Navigant team, in consultation with the PG&E team:

1. Select representative set of 20 feeders as the basis to model PG&E's entire distribution system containing over 3,000 individual feeders
2. Develop three (high, mid, low) system-level retail and wholesale DGPV capacity forecast scenarios for 2015 through 2024 (forecasting conducted by PG&E)
3. Allocate system-level forecast to each of over 3,000 distribution feeders (allocation of retail scenario conducted by PG&E; allocation of wholesale scenario conducted jointly)
4. Conduct parametric studies of distribution impacts and costs via simulation models for each scenario
5. Estimate upgrade costs for all PG&E feeders based on parametric studies of representative feeders; upgrade cost methodology, triggers, and values informed by PG&E
6. Calculate distribution capacity deferral benefits at the feeder level based on the Effective Load-Carrying Capability (ELCC) methodology for distribution assets
7. Conduct transmission impact analysis for PG&E service territory via PSLF simulation model for each scenario

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[2] *Distributed Generation Integration Cost Study, Analytical Framework*, CEC-200-2013-007, September 2014.

[3] Ibid.

8. Develop net costs and benefits for each scenario & DGPV forecast (9 total)

Navigant applied well-known analytical tools to predict costs and benefits at the feeder level. Study methods and assumptions are consistent with approaches and assumptions PG&E engineering and planning uses for its internal studies. The two primary analytical tools, the CYME distribution load flow and PSLF transmission network model, are the same as those used by PG&E and other California utilities. Model databases and criteria applied by PG&E also are used for evaluating DGPV costs and benefits.

The representative circuit methodology is designed to develop factual, system-wide estimates of costs and benefits; but it may not be sufficiently granular to inform feeder-specific investment decisions, since it relies on representative circuit characteristics.

This Study was performed using data available from PG&E and other sources prior to the completion of PG&E's Electric Distribution Resources Plan (DRP) filed with the California Public Utilities Commission on July 1, 2015. Accordingly, the Study did not use the data included in and supporting PG&E's DRP, including PG&E's analysis of estimated distributed energy resources integration (or hosting) capacity on all 3,000+ distribution feeders that may be available on PG&E's distribution grid. However, Navigant has compared PG&E's DRP Integration Capacity Analysis to the representative feeders used for this Study, and does not expect that the DRP data would materially change the results of this Study.

This Study's general conclusions regarding the potential net benefits and avoided costs attributable to deployment of DGPV on PG&E's grid also did not take into account the unique and locally-specific variables that affect the safety, operational, reliability and unit cost criteria applicable to the potential ability of DGPV to enable PG&E to re-schedule local distribution capacity upgrades to later times and thus avoid certain costs to its grid. Accordingly, the estimates of potential DGPV net benefits in this Study are subject to uncertainty based on the local variables that affect PG&E's distribution capacity planning and operation.

Forecast Scenarios

The study includes scenarios for a range of retail and wholesale DGPV capacities representing low, mid, and high capacity projections. The study includes evaluation of nine DGPV scenarios comprised of a mix of retail and wholesale capacity for the years 2015 through 2020. Although the primary objective of the study is to evaluate retail impacts and net costs, wholesale DGPV capacity must be jointly evaluated with retail DGPV, as each will contribute to potential costs and benefits on common feeders.

The retail DGPV scenarios examined are summarized in Table 1-1; existing capacity at the end of 2014 is estimated to be 1,363 MW in PG&E's territory. Incremental capacity additions were allocated across the feeders for each scenario.

Table 1-1. Retail DGPV Scenario

Scenario	Retail DGPV Forecast	2015-2024 Incremental Capacity Additions* (MW)	Cumulative Installed Capacity 2024* (MW)
Low Penetration	CED 2013 Mid-Demand Case for 2013 IEPR	**1,160 MW**	**2,523 MW**
Mid Penetration	PG&E DGPV Forecast for 2015 Sales Planning/IEPR	**4,239 MW**	**5,602 MW**
High Penetration	Mid-Penetration and ... • Full ZNE compliance starting in 2020 • NEM 1.0 and ITC 'Gold Rush' through 2017 • Post ITC consolidation of solar marketing into more lucrative CA markets	**6,573 MW**	**7,937 MW**

*Source: PG&E Forecast. * Capacity is CEC AC Nameplate capacity.*

Importantly, PG&E forecasted retail DGPV capacity for each distribution feeder, which enabled evaluation of DGPV costs and benefits for individual feeders and substations. This level of detail ensures increased accuracy and confidence in results, and is an enhancement to the CEC analytical framework that was applied in this study, and well beyond the level of detail and rigor evidenced in prior statewide studies. The majority of PG&E's 3,000-plus feeders are assigned some amount of PV capacity that varies according to the number of eligible Net Energy Metering (NEM) customers and participation factors such as electric usage, total electric bills, income, home value, and other economic drivers. As a result, the amount of DGPV capacity forecasted for each distribution feeder varies significantly throughout PG&E's service territory.

The wholesale DGPV scenarios examined are summarized in Table 1-2; existing capacity at the end of 2014 is estimated to be 282 MW in PG&E's territory. Similar to retail DGPV, wholesale DGPV is forecast at the feeder level. PG&E developed wholesale DGPV capacity forecasts at the system level, and Navigant and PG&E jointly allocated capacity to the county level. Navigant then allocated these forecasts to the feeder level. Navigant applied a scoring approach that evaluated site suitability based on 20 criteria, including environmental, public use, customer and building density, terrain, forestation, and other relevant environmental factors. Navigant also considered the level of available hosting capacity when allocating wholesale DGPV to each feeder.

Table 1-2. Wholesale DGPV Scenario

Wholesale Forecast Methodology			
Scenario	**Basis of Projection**	**2015-2024 Incremental Capacity Additions* (MW)**	**Cumulative Installed 2024* (MW)**
Low	Full subscription ("net open positions") under existing CPUC mandated procurement programs (*ReMAT, PV Program, RAM, Green Option Tariff*)	**284 MW**	**566 MW**
Mid	Mid-point between high and low scenarios	**1399 MW**	**1681 MW**
High	"Distributed Solar – PG&E" under the CPUC-mandated '*High DG, 40% RPS by 2024, Mid AAEE'* Planning Scenario for the 2014 LTPP	**2514 MW**	**2796 MW**

Source: PG&E.

** Capacity is CEC AC Nameplate capacity. High forecast scenario basis was developed prior to SB 350 which proposes and even higher (50%) RPS*

Distribution Costs

Distribution costs and benefits are evaluated at the primary feeder level for increasing amounts of DGPV capacity. Secondary costs are excluded due to the absence of data to support assignment of costs, the omission of which may understate actual costs as installed DGPV capacity increases. A formula predicting costs as a function of DGPV capacity was developed for each of the 20 representative feeders. These costs are determined by feeder simulation studies conducted for each representative feeder by increasing DGPV capacity up to the feeder rating. The cost of feeder upgrades to accommodate DGPV, where applicable, is determined at discrete levels of increasing capacity, with a sufficient number of capacities to ensure a statistically valid curve fit and resulting formulas (linear or polynomial). Every feeder within a cluster is assigned the same formula. The cost of distribution upgrades is determined based on the DGPV capacity forecasts for each feeder under each scenario.

Of the 20 representative feeders, most do not experience loading or voltage violations until DGPV capacity reaches 50 percent of the feeder rating. Two are able to interconnect DGPV up to 100 percent of the feeder rating without upgrades. For 21 kV feeders, many are able to accommodate over 10 MW of greater of DGPV, as these feeders typically are rated 20 MW.

Many impacts requiring mitigation or upgrades were addressed by adjusting inverter power factor settings on wholesale DGPV.[4] PG&E retains authority in its Interconnection Tariff to require DGPV owners to set power factors at non-unity. Many feeders experience voltages above established limits for high penetration DGPV, particularly light load feeders where reverse power flow can be high during the mid-day DGPV peak. Feeders with non-compliant voltages often were mitigated by setting wholesale inverter power factors at non-unity, typically 0.95 leading; a mitigation option without associated costs. For the most part, our findings indicate that adjusting the power factor settings enabled DGPV capacity to reach 50 percent of the feeder rating without the need for other upgrades.

Where inverter power factor adjustments were unable to mitigate voltages or when line sections were overloaded, feeder upgrades in the form of reconductoring were the most dominant upgrade. Many PG&E main line and lateral feeder segments are equipped with small #2 and #4 legacy conductors, which are susceptible to overload and voltage perturbations due to high line impedances. At up to $500,000 per mile for overhead lines and $3 million for underground cable, the cost of line reconductoring is a primary cost driver when other measures fail to resolve the violation. However, reconductoring typically was not required until DGPV capacity reached 50 percent of the feeder rating or higher; and then, only on a subset of the 20 representative feeders. The cost of applicable feeder and substation upgrades and mitigation options is summarized in Table.

Table 1-3. Unit Cost – Mitigation Options

Description	Cost ($000)
Reconductor Overhead - 1 Phase (per mile)	$ 250
Reconductor Overhead - 3 Phase (per mile)	$ 500
Capacitor Bank Setting Adjustment	$ 5
New Capacitor Bank	$ 25
Inverter Power Factor Adjustment	$ -
New Distribution Feeder*	$ 1,000
Replace Line Fuse	$ 10
New Recloser	$ 80
New 3 Phase Underground Cable (per mile)	$ 3,000
New Regulator	$ 110
New Substation XFMR Bank	$ 5,000
New Substation	$ 15,000

*Based on cost of new feeder position and one mile of new line

In addition to feeder upgrades needed to address voltage or loading violations, Navigant included costs for information system upgrades, administrative expense, and operation and maintenance expense; each needed to support interconnection and operation of large quantities of DGPV. These include enhancements or expansion of DMS and CIS, which Navigant assumed would progressively require

[4] PG&E engineering informed Navigant that it does not apply this requirement to smaller NEM DGPV as these installations are not inspected by PG&E.

upgrades as DGPV installation approached penetration levels, where tens or hundreds of thousands of DGPV installations would tax the capability and functionality of existing systems. In particular, the ability to track and monitor the status of high penetration DGPV, including real or near real-time assessment of switching operations and other incidents affecting distribution performance in the presence of distributed behind-the-meter DGPV that may not (or should not) ride through sustained or momentary interruptions.[5]

Table 1-4 presents cumulative annual cost of distribution system upgrades for retail DGPV for the mid-capacity scenario (retail and wholesale DGPV). This table does not reflect the impact of wholesale DGPV, distribution-related benefits or transmission-related costs or benefits.

Table 1-4. Retail DGPV System Upgrades for Mid-Capacity Scenarios

	PV Capacity (MW)			System Upgrade Cost				
Year	Retail	Wholesale	Total	Dist Upgrade	Overhead	O&M	Total	$/MWH
2015	488	71	559	$5	$1	$1	$7	$8
2016	1103	181	1284	$6	$3	$2	$12	$6
2017	1578	336	1915	$14	$5	$3	$22	$8
2018	1965	498	2463	$19	$6	$3	$28	$8
2019	2355	642	2997	$34	$8	$4	$45	$11
2020	2749	792	3541	$45	$9	$4	$58	$12
2021	3138	962	4100	$58	$11	$5	$74	$13
2022	3538	1096	4635	$73	$12	$5	$90	$15
2023	3943	1237	5180	$88	$14	$6	$109	$16
2024	4353	1385	5738	$111	$16	$7	$134	$18

* Net cost of retail DGPV only. All costs and benefits in nominal dollars (one-time costs in millions).

Wholesale DGPV net cost is significantly higher, typically by a factor of up to three- or four-to-one, depending on the year and amount of retail and wholesale DGPV capacity. Unlike retail DGPV, which is distributed throughout the entire feeder, wholesale DGPV is often concentrated at just a few locations on a feeder, and therefore, proportionally create a greater number of feeder voltage and line loading violations.

Navigant conducted a feeder-by-feeder analysis of retail and wholesale DGPV impacts, and allocated interconnection costs based on relative percentage of retail versus wholesale capacity on each feeder. Unlike distribution, where DGPV capacity is located on most of PG&E's 3000+ feeders, wholesale DGPV is located on 100 to 300 feeders depending on the DGPV capacity scenario. The smaller number of feeders with wholesale DGPV is due to the locational constraints described in Section 2. Because greater amounts of wholesale DGPV capacity is installed on individual feeders, the impact, and associated interconnection cost, is higher than that of retail DGPV. Further, in earlier years, the amount of

[5] DMS upgrades could include the capability to conduct real-time state estimation to predict feeder loadings and voltages when feeders segments are transferred to adjacent circuits during maintenance or outage with DGPV capacity on and offline.

wholesale capacity is small, resulting in lower net cost. The higher net cost of wholesale interconnection at higher capacity is due to larger size of wholesale DGPV and the absence of diversity on feeders. Table 1-5 presents cumulative retail and wholesale distribution costs for years 2015 through 2024.

Table 1-5. Mid-Retail & Mid-Wholesale DGPV Scenario

Year	PV Capacity (MW)		System Upgrade Cost ($/MWh)	
	Retail	Wholesale	Retail	Wholesale
2015	488	71	$8	$3
2016	1103	181	$6	$6
2017	1578	336	$8	$29
2018	1965	498	$8	$27
2019	2355	642	$11	$35
2020	2749	792	$12	$48
2021	3138	962	$13	$54
2022	3538	1096	$15	$59
2023	3943	1237	$16	$61
2024	4353	1385	$18	$64

Table 1-5 confirms distribution upgrades for wholesale DGPV is significantly higher than retail: $64/MWh of installed capacity for the mid-level wholesale scenario and $18/MWh for the mid-level retail DGPV scenario. This finding results from the impact of wholesale DGPV on feeder performance.

Gross distribution-related costs for DGPV could be reduced through application of policies or complementary technologies that align system performance with grid needs. For instance, a policy that guides deployment of DGPV to feeders with existing integration capacity would reduce the likelihood that upgrades would be needed. Similarly, policies that encourage the right-sizing of systems to reduce exporting could enable DGPV to be deployed with reduced system impact.

Distribution Benefits

All benefits evaluated are those that directly impact the utility; no external, customer or societal benefits are assigned in the analysis. The primary distribution benefits considered include deferred feeder and substation capacity, line and equipment losses, reliability, and voltage benefits. Of these, deferred capacity offers the greatest benefits opportunity.

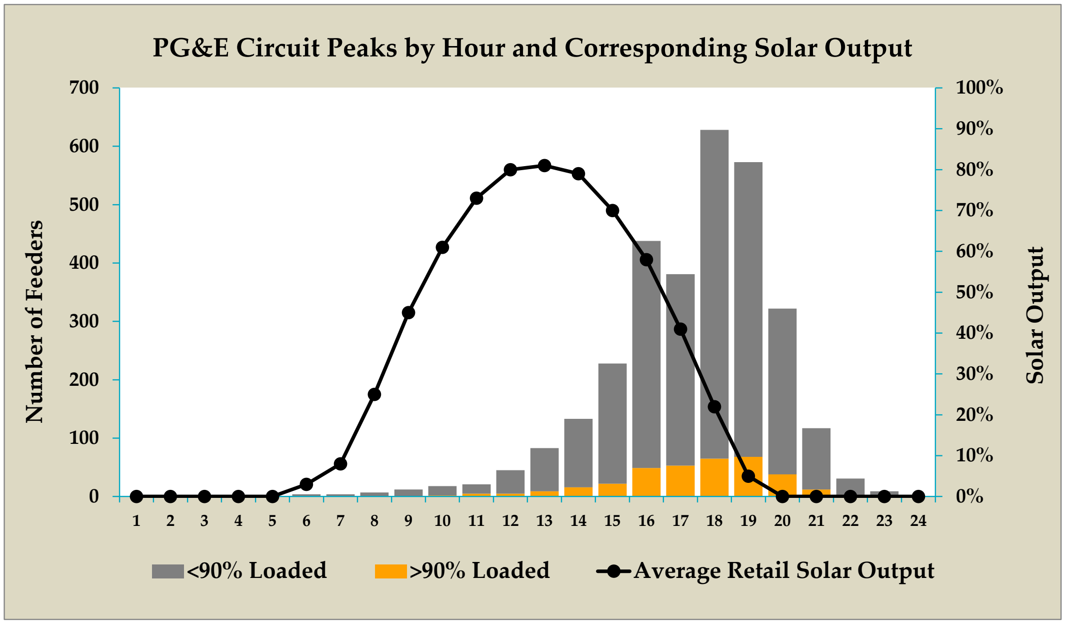
Distribution Capacity Deferral: The dominant benefit associated with DGPV is distribution capacity deferral. Navigant quantified capacity deferral benefits using methods comparable to those used by PG&E planning. Potential distribution capacity benefits were evaluated for each substation and feeder; approximately 800 and 3100, respectively. The first step entailed preparation of a capacity load balance prior to DGPV connection to identify the timing and magnitude of annual capacity surpluses or deficits. A capacity benefit is assigned when the amount of firm DGPV capacity exceeds feeder or substation capacity deficits. The duration of the capacity benefit ranged from one to 20 years, recognizing that load growth could exceed the amount of firm DGPV capacity added each year. Firm DGPV capacity is based on the ELCC calculation performed for each feeder.[6] The average ELCC for DGPV deployed on a distribution feeders and substation transformers deferred ranged from 0.30 to 0.40.[7]

The subset of distribution assets that could be deferred by DGPV is limited. On average, PG&E upgrades 10 to 12 feeders and seven to 10 substation transformers banks annually, representing the total population of potentially deferrable assets. One new substation is installed every five to 10 years. These quantities reflect PG&E planning criteria and practices, which include load transfers to maximize utilization of existing assets and minimize cost. The number of feeder deferred due to DGPV connections ranged from a low of three to a high of 26 annually, over the 10-year planning horizon, corresponding to low retail and wholesale scenarios, and high retail and wholesale scenarios, respectively. A maximum of two substation transformer banks are deferred annually (high DGPV scenario).

Navigant determined that distribution capacity deferral potential was extremely limited by the large number of feeders and substations that experience early evening peaks in summer; a very small percentage of feeders have mid-day peaks, and, of these, most are winter-peaking in the San Francisco area, where solar capacity projections and daily output are lower. Accordingly, DGPV deployed on most feeders is assigned a relatively low ELCC and firm capacity relative to maximum output. Figure 1-2 confirms most PG&E feeders peak between 6 p.m. and 7 p.m. during the summer, including those near capacity ratings, while less than 10 percent peak during hours when DGPV output is highest. This phenomenon is a function of the customer load profile for each feeder. Feeders serving primarily residential customers tend to peak in the evening, while feeders serving primarily commercial/industrial customers tend to peak closer to mid-day.

[6] PG&E performed ELCC values for the study.
[7] ELCC is expected to drop significantly under a 50 percent RPS scenario. Thus, the ELCC estimates in this study are on the high side and overstate benefits in later years.

Figure 1-2. Feeder Versus PV Hourly Profiles



Navigant's evaluation of potential distribution benefits is described below. Where applicable, distribution benefits are quantified and compared to the cost of distribution upgrades.

Line and Equipment Losses: The results of the distribution simulation studies indicate line and equipment losses tend to decline for lower DGPV capacity levels, but generally increase for higher DGPV capacities, particularly on feeders where DGPV capacity exceeds feeder load. Further, on many feeders, total energy deliveries increase due to voltage rise caused by DGPV capacity, particularly on end-of-line sections where voltages increase above levels measured at the substation bus. For these reasons, Navigant concluded that loss increases and decreases offset, depending on the level of DGPV capacity deployed, which tends to understate cost for higher DGPV capacity cases where net line losses often are higher.

Reliability: Given the intermittent nature of solar PV, and absent enhanced smart technologies not generally available today or in the foreseeable future, enhanced reliability stemming from DGPV is very limited. The presence of DGPV capacity will not reduce the frequency of customer interruptions, nor will it reduce the duration of interruptions. It is possible to reduce the duration of interruptions via automated transfer schemes, where greater amounts of load could be transferred to unfaulted line sections; however, this scheme is feasible only for highly automated transfer schemes with centralized intelligent systems that monitor, track, and control DGPV. These schemes generally are not available today.

<u>Voltage Support/Power Quality:</u> Active voltage support from DGPV inverters is anticipated over the next several years, but not implemented today beyond pilot evaluations.[8] Navigant included in its evaluation passive voltage support from DGPV inverters, described earlier, where overvoltage conditions are mitigated via power factor adjustments, thereby avoiding more costly upgrades such as line reconductoring and voltage regulating devices.

Gross distribution-related benefits for DGPV could increase through application of policies or complementary technologies that align system performance with grid needs. For instance, a policy that guides deployment of DGPV to specific feeders or substations experiencing peak loads in the daytime could help to align the solar output with the distribution peak. Similarly, policies that encourage deployment of complementary technologies, such as distributed energy storage, could enable DGPV to shift energy output to the evening and address evening peaking feeders. The cost of implementing such policies would need to be evaluated against any prospective increase in benefits.

Table 1-6 presents cumulative distribution costs and benefits (retail only) for the mid-retail, mid-wholesale scenario, including net costs on a total and unitized basis. Results indicate minimal benefits in early years (compared to cost); however, benefits increase in later years as opportunities for capacity deferral increase, thereby offsetting some of the costs required for interconnection.

Table 1-6. Distribution Costs and Benefits, Mid-Retail, Mid-Wholesale Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	**559**	$7	$0	**$7**	$14	$8
2016	1,103	181	**1,284**	$12	$0	**$11**	$10	$6
2017	1,578	336	**1,915**	$22	$1	**$21**	$13	$8
2018	1,965	498	**2,463**	$28	$2	**$27**	$14	$8
2019	2,355	642	**2,997**	$45	$4	**$41**	$17	$10
2020	2,749	792	**3,541**	$58	$8	**$51**	$18	$11
2021	3,138	962	**4,100**	$74	$11	**$63**	$20	$11
2022	3,538	1,096	**4,635**	$90	$15	**$76**	$21	$12
2023	3,943	1,237	**5,180**	$109	$22	**$87**	$22	$13
2024	4,353	1,385	**5,738**	$125	$30	**$95**	$22	$13

Transmission Costs and Benefits

Navigant evaluated transmission impacts for low, mid, and high DGPV capacity scenario via PSLF network load flow simulation analyses of the PG&E system within service territory boundaries. Impacts are limited to transmission assets only, excluding impacts to adjacent utility systems and generation located within and outside of the balancing areas for PG&E service territory.[9] It includes a network

[8] The CPUC Rule 21 Working Group has addressed requirements associated with the implementation of local and centralized active inverter control. Inverter technology is capable of providing voltage support via adjustable power factors. Underwriter Laboratories is expected to approve enhanced inverters within the next year or two.
[9] Navigant recognizes the impact of DGPV on generation scheduling, ancillary services, regulation requirements, and intertie transfers can be significant from an energy production cost perspective, particularly for high DGPV

model and large renewable scenario based on the most current Western Electricity Coordinating Council (WECC) and California Independent System Operator (CAISO) base model for 2024.

For low DGPV capacities, Navigant determined that the DGPV capacity could be interconnected with minimal system upgrades. However, Results confirm transmission impacts and interconnection costs increase in later years as transmission impacts become more prevalent. These impacts include reactive support caused by solar displacement of conventional generating sources and upgrades to lower voltage transmission to relieve overloads.

Similar to distribution, transmission benefits also are limited, as most transmission upgrades are needed for reliability, security, or generation delivery (including large renewable capacity), and therefore, not deferrable. Where upgrades are required due to load growth—mostly lower voltage 115 kV and below—forecast scenarios suggest that there is insufficient firm DGPV capacity available to effect a deferral. For lower and moderate capacity scenarios, DGPV capacity can be interconnected with nominal system upgrades. The primary enhancement includes reconductoring of overloaded 70 kV and 115 kV lines. Several B (n-1) contingencies could potentially be addressed by adjusting post-contingencies generation outputs as opposed to construction of new or upgraded lines and substations, but these are beyond the scope of the subject study. Accordingly, transmission benefits are limited to line loss reduction.

Table 1-7 presents transmission costs and benefits (retail only) for the mid-retail, mid-wholesale DGPV scenario. Results confirm transmission impacts and interconnection costs are very low in earlier years when DGPV capacity is low, but increases in later years as transmission impacts become more prevalent.

Table 1-7. Transmission Costs and Benefits, Mid-Retail, Mid-Wholesale Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	181	1,284	$1	$1	($0)	($0)	($0)
2017	1,578	336	1,915	$22	$2	$20	$13	$7
2018	1,965	498	2,463	$40	$2	$38	$19	$11
2019	2,355	642	2,997	$59	$3	$56	$24	$14
2020	2,749	792	3,541	$78	$4	$74	$27	$15
2021	3,138	962	4,100	$98	$5	$94	$30	$17
2022	3,538	1,096	4,635	$119	$5	$114	$32	$18
2023	3,943	1,237	5,180	$141	$6	$135	$34	$20
2024	4,353	1,385	5,738	$165	$7	$157	$36	$21

Summary Results

Table 1-8 presents cumulative net retail cost of T&D system upgrades for the mid-retail and wholesale scenario (i.e., the baseline DGPV scenario). Results indicate annual costs exceed savings, with net costs ranging from $6 million in 2015 to just above $250 million cumulatively by 2024 for the high-retail

penetration cases that require shut down or curtailment of generation unit output. Navigant did not quantify these impacts, as the primary objective of the study is to identify net T&D costs.

scenario.[10] When cost is unitized as a function of DGPV energy production, cost per MWh ranges from $7/MWh in 2015 to $33/MWh in 2024 for the mid retail and mid wholesale scenario.[11]

Table 1-8. Net T&D Costs, Mid-Retail, Mid-Wholesale Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	**559**	$7	$1	$6	**$13**	**$7**
2016	1,103	181	**1,284**	$13	$2	$11	**$10**	**$6**
2017	1,578	336	**1,915**	$44	$3	$41	**$26**	**$15**
2018	1,965	498	**2,463**	$69	$4	$65	**$33**	**$19**
2019	2,355	642	**2,997**	$104	$7	$97	**$41**	**$23**
2020	2,749	792	**3,541**	$136	$11	$125	**$45**	**$26**
2021	3,138	962	**4,100**	$172	$15	$157	**$50**	**$29**
2022	3,538	1,096	**4,635**	$210	$20	$190	**$54**	**$31**
2023	3,943	1,237	**5,180**	$250	$28	$222	**$56**	**$32**
2024	4,353	1,385	**5,738**	$290	$37	$253	**$58**	**$33**

The retail cost component of DGPV interconnection costs is presented separately from wholesale in the above tables to inform NEM pricing recommendations. Retail interconnection costs range from $6 million in 2015 to $253 million in 2024. Transmission costs are allocated equally to retail and wholesale DGPV based on the relative amount of DGPV capacity, as it was not realistic nor necessary to allocated transmission costs by location. Among other factors, the operation of the transmission system in a network configuration obviates the need to allocate costs to specific locations.

The primary rationale supporting the finding that DGPV T&D costs exceed benefits is the lack of coincidence between the time of maximum DGPV output and transmission and distribution feeder peak loads, which results in minimal amounts of deferred capacity.

Other high-level findings and observations from the study include:

- Higher retail DGPV penetration significantly increases unit and total net cost. Low retail DGPV capacity results in minimal interconnection cost, as they capacity is "spread" over many feeders, thereby mitigating impacts. However, with higher retail penetration, up to 4,000 MW or greater by 2024, feeder impacts are more dominant.
- Distribution upgrade costs are concentrated in a few key circuits with high DGPV penetration (typically less than 10 percent of feeders require upgrades). This finding is driven by wholesale DGPV capacity, which is located on a smaller subset of feeders with greater associated impacts.

[10] The amount of wholesale DGPV for each retail DGPV forecast in the table is 1,385 MW in 2024.

[11] When wholesale interconnection costs are included, cumulative net costs at $476 million in 2024 for the baseline scenario. When measured on a unitized $/MWh basis, net retail and wholesale cost for the baseline case ranges from $14/MWh in 2015 to $47/MWh in 2024.

- Most system upgrade costs are socialized under current NEM policy, although this study confirms costs tend to be localized among a small percentage of distribution feeders. The ability to direct customers to install DGPV on feeders with significant integration capacity would mitigate potential cross subsidies, as would policies that encourage customers to limit their exports to the grid
- Gross distribution-related benefits for DGPV could increase through application of policies and/or complementary technologies that align system performance with grid needs.
- For lower and moderate capacity scenarios, DGPV capacity can be interconnected with nominal transmission system upgrades. Few impacts were identified on network transmission rated 230 kV and above. None require mitigation or upgrades.
- There are significant shifts in intertie flows for high DGPV capacity scenarios; particularly on Path 66 (~ 2,500 MW reduction in flows between Oregon and California) and up to an 1,800 MW increase on Path 26 south to SCE. Although these findings may have significant cost implications, the impacts are not quantified as they are associated with wholesale energy sales.
- Similar to distribution, the transmission system peak occurs during early evening hours, which limits potential transmission capacity deferral benefits; the primary benefits is an average incremental line reduction of 2 percent.
- For subsequent studies, it may be appropriate to conduct dynamic stability analysis for contingencies that exhibit signs of or appear susceptible to large and rapid voltage swings.

2. Background and Scope

2.1 Overview

Navigant conducted this Distributed Generation Photovoltaic (hereafter, the "DGPV" study) Transmission and Distribution (T&D) Impact Study as a research effort on behalf of Pacific Gas and Electric Company (PG&E). The study is designed to develop a range of T&D costs and benefits resulting from the interconnection of higher levels of DGPV capacity on PG&E's electric grid. The study is not intended to evaluate the cost/benefit of optimizing deployment of DGPV, which would result in a different set of costs and benefits, and is dependent on policy and technology development that cannot be anticipated. The study addresses the cost/benefit impacts of market-driven adoption that is not directly guided by PG&E or market price signals.

Results are compared to prior studies completed by E3 for California investor-owned utilities that predicted positive net benefits from DGPV for each utility. The study examines multiple DGPV penetration scenarios and separately attributes costs and benefits to retail and wholesale DGPV systems for the years 2015 through 2024.[12] Navigant's methodology builds upon an analytical framework developed by Navigant on behalf of the California Energy Commission (CEC), adding greater rigor via use of PG&E studies and prior research.

2.2 Study Objectives and Scope

The objective of this study is to develop a range of financial values (positive or negative) needed to facilitate the integration of expected (higher) levels of DGPV into PG&E's electric grid.

The project scope includes four primary tasks, each of which are designed to predict how T&D net costs vary as a function of increasing amounts of retail and wholesale DGPV interconnected on PG&E's distribution system.

1. Establish quantitative baseline of existing grid conditions
2. Calculate transmission and DGPV interconnection costs and benefits for a range of DGPV capacity scenarios
3. Account for variation in interconnection costs and benefits by
    - DGPV type, size and penetration levels
    - Clustering (on different segments of a feeder)
4. Allocate costs to retail and wholesale components, and demonstrate how net cost vary as a function of differing levels of retail and wholesale DGPV capacity

[12] Retail DGPV capacity typically is less than 1 MW, connected behind the meter and owned by PG&E retail customers. Wholesale DGPV resources are defined as generating resources, less than or equal to 20 MW but greater than or equal to 1 MW, connected to PG&E's distribution grid, on the utility side of the meter. Wholesale DGPV capacity may be owned by third parties.

2.3 Methodology

The study methodology is based on the CEC's Analytical Framework[13], but with additional detail and analytical rigor. The primary assumptions about upgrade costs, triggers, and values were informed by PG&E and are more conservative (i.e., result in lower costs) than those used in the previous CEC study for Southern California Edison (SCE).[14] The following steps highlight the overarching methodology applied by the Navigant team in consultation with the PG&E team:

1. Select representative set of 20 feeders as the basis to model PG&E's entire distribution system containing over 3,000 individual feeders
2. Develop three (high, mid, low) system-level retail and wholesale DGPV capacity scenarios for 2015 through 2024 (forecasting conducted by PG&E)
3. Allocate system-level scenario to over 3,000 distribution feeders (allocation of retail scenario conducted by PG&E; allocation of wholesale scenario conducted jointly)
4. Conduct parametric studies of DGPV impacts on PG&E's distribution and interconnection costs via use of load flow simulation models for increasing amounts of DGPV capacity
5. Estimate upgrade costs for all PG&E feeders based on parametric studies of representative feeders; upgrade cost methodology, triggers, and values informed by PG&E
6. Calculate distribution capacity deferral benefits at the feeder level based on the Equivalent Load-Carrying Capability (ELCC) methodology for radial distribution assets
7. Conduct transmission impact analysis for PG&E service territory via PSLF simulation model for each scenario
8. Develop net costs and benefits for each DGPV scenario (nine total)
9. Allocate costs and benefits to retail and wholesale DGPV capacity

Navigant applied well-known analytical tools to predict costs and benefits at the feeder level. Study methods and assumptions are consistent with approaches and assumptions PG&E engineering and planning uses for its internal studies. The two primary analytical tools, the CYME distribution load flow and PSLF transmission network model, are the same as those used by PG&E and other California utilities. Model databases and criterion applied by PG&E also are used for evaluating DGPV costs and benefits.

The representative circuit methodology is designed to develop system-wide estimates of costs and benefits; but it may not be sufficiently granular to inform feeder-specific investment decisions, since it relies on representative circuit characteristics.

2.4 Guiding Principles

Navigant and the PG&E project team frequently reviewed and updated study methods and assumptions to ensure results are accurate and defensible. To ensure independence analytical

[13] *Distributed Generation Integration Cost Study, Analytical Framework*, CEC-200-2013-007, September 2014.

[14] Ibid.

rigor, Navigant prepared the following set of principles to guide the study team and to ensure these objectives were met throughout all phases of the study.

1. Study methodology should follow the CEC's Analytical Framework, but with additional detail and analytical rigor.
2. Methodology should provide sufficient flexibility to update analytical approach as new data becomes available (PG&E and industry).
3. Comprehensive, industry-accepted simulation models and methods should be applied to produce the most accurate results.
4. Interconnection costs and benefits should be based on a realistic forecast of enabling solutions and technologies.
5. Study methods and results should be transparent and consistent with statewide initiatives and regulatory mandates.
6. All assumptions, methods, and results are reviewed and vetted by a cross-section of PG&E experts throughout the organization.

2.5 Study Assumptions

The study includes the following key assumptions over the 10-year forecast. Additional details and assumptions are presented in subsequent sections.

- **Distribution feeder selection and analysis**
  - Twenty representative feeders were selected based on updates to December 2012 DG Impact study, suitable for DGPV, energy efficiency (EE), demand response (DR), and other DG technologies[15]
  - Steady state and dynamic impacts are considered in the analysis (dynamic analysis informed by December 2012 study that researched PV impacts)
  - No limitations on DGPV capacity based on tie transfers for maintenance or outages
  - DGPV performances and operations must meet IEEE 1547 Interconnection Guidelines
- **Costs & benefits**
  - Distribution costs and benefits are derived for each feeder and substation, with retail and wholesale values presented separately
  - Transmission costs and benefits for transmission are assets only (excludes cost impact on generation operations, scheduling , intertie transactions and impacts on adjacent systems)
  - Costs include distribution management system (DMS) and customer information system (CIS) upgrades are needed for improved visualization, tracking, and analysis of DGPV impacts and operations

[15] "Impact of Solar Photovoltaic (DGPV) System on the Pacific Gas & Electric Distribution Grid (Volume 1, Rev.1)", Quanta Technology

- **Technology options and solutions**
  - Mitigation and upgrades of DGPV impacts are based on currently available technology
  - Inverter power factor is adjustable for wholesale DGPV from 0.95 leading to 0.95 lagging for voltage support; power factor is fixed (no active control of inverter real or reactive output)

3. Solar Scenarios

This section describes the forecasting of retail and wholesale solar DGPV for the years 2015 through 2024 that is used as the basis for Navigant's assessment of costs and benefits. Retail DGPV refers to smaller solar installations that are at or near customer load and designed to serve that load, while wholesale DGPV typically is much larger (e.g. from 1 to 20 MW), owned by third parties and often is connected to the primary distribution system. The preparation of separate scenarios for retail and wholesale solar DGPV is critical for several reasons, including differences in the following:

- Assignment of cost responsibility for system upgrades and interconnection costs
- Sizes of retail versus wholesale solar DGPV sizes
- Concentrated wholesale versus diffuse retail geographic distribution of impacts
- Utilities are more likely to be able to control/mitigate impacts from wholesale DGPV due the large amounts of solar capacity at single locations and non-NEM status

PG&E Solar DGPV scenarios are incremental to existing and committed DGPV capacity up to and including 2014.

The study includes scenarios for a range of retail and wholesale DGPV capacities scenarios representing low, mid, and high projections. The study includes evaluation of nine DGPV scenarios comprised of a mix of retail and wholesale capacities for the years 2015 through 2020. Although the primary objective of the study is to evaluate retail impacts and net costs, wholesale DGPV capacity must be jointly evaluated with retail DGPV, as each contribute to potential costs and benefits on feeders where both classifications of PV is installed.

3.1 Retail Solar Scenario

The existing retail DGPV capacity at the end of 2014 within PG&E's service territory is estimated to be 1,363 MW. The study uses PG&E capacity scenarios for each retail DGPV scenario. PG&E allocated incremental DGPV capacity additions to individual distribution feeders for each scenario, an important development, as it enabled an analysis of DGPV impacts for each feeder. Table 3-1 summarizes the source and incremental retail DGPV capacity for low, mid (trajectory), and high penetration scenarios. A detailed description of the methods and results of the DGPV scenarios are contained in PG&E's Distribution Resources Plan filed with the CPUC on July 1, 2015, Appendix C, Chapter 3.[16]

[16] [INSERT LINK to Retail PV Forecast Section of report]

Table 3-1. Retail DGPV Scenario

Scenario	Retail DGPV Forecast	2015-2024 Incremental Capacity Additions* (MW)	Cumulative Installed Capacity 2024* (MW)
Low Penetration	CEC's CED 2013 Mid-Demand Case Forecast for 2013 IEPR proceeding	**1,160 MW**	**2,523 MW**
Mid (Trajectory) Penetration	PG&E's Retail PV Forecast submitted to the CEC for the 2015 IEPR proceeding (Form 3.3). Also PG&E's DRP DER Growth Scenario 1	**4,239 MW**	**5,602 MW**
High Penetration	Mid-Penetration and ... • Full ZNE compliance starting in 2020 • NEM 1.0 and ITC 'Gold Rush' through 2017 • Post ITC consolidation of solar marketing into more lucrative CA markets • PG&E's DRP DER Growth Scenario	**6,573 MW**	**7,937 MW**

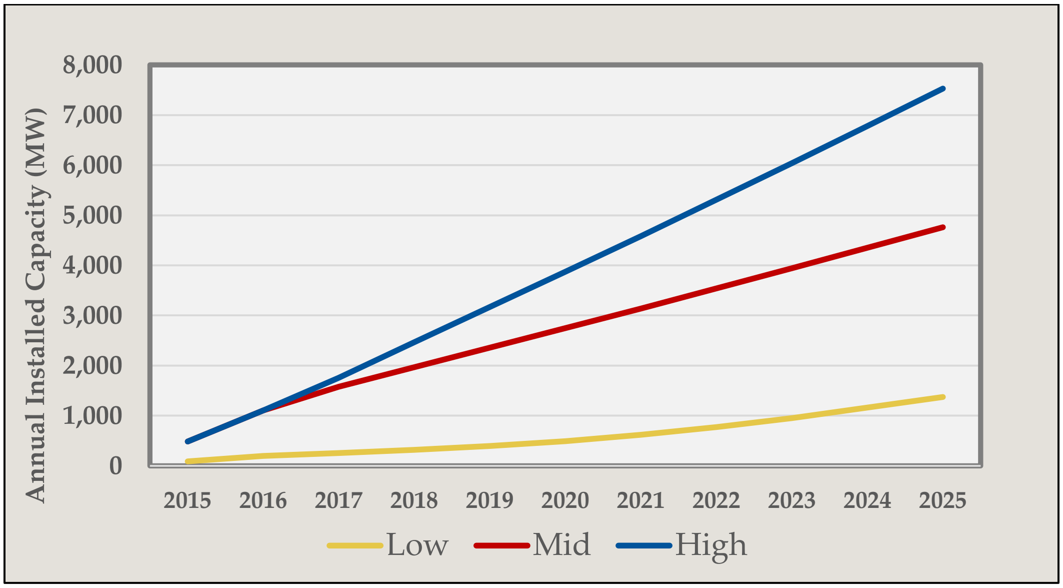
Source: PG&E

** Capacity is CEC AC Nameplate capacity.*

Figure 3-1 presents existing and future retail PV capacity over the 10-year study horizon. As noted, total DGPV installed capacity is allocated to individual feeders for evaluation of the distribution impact of each solar scenario. The DGPV capacity scenario ranges from a low of slightly less than 10 percent of the system peak in 2024 to a high of about 30 percent of the 2024 peak. The PG&E system is summer peaking, with the annual peak typically occurring between 4:00 and 6:00pm when solar output is lower.[17] The retail scenarios are combined with wholesale DGPV scenarios to assess total DGPV capacity impacts on a composite basis.

[17] Different areas in PG&E's system peaks at different seasons and time of day. For example, the San Francisco area is winter peaking due to moderate summer cooling load versus central regions, which experience high later afternoon cooling loads.

Figure 3-1. Retail DGPV Scenarios

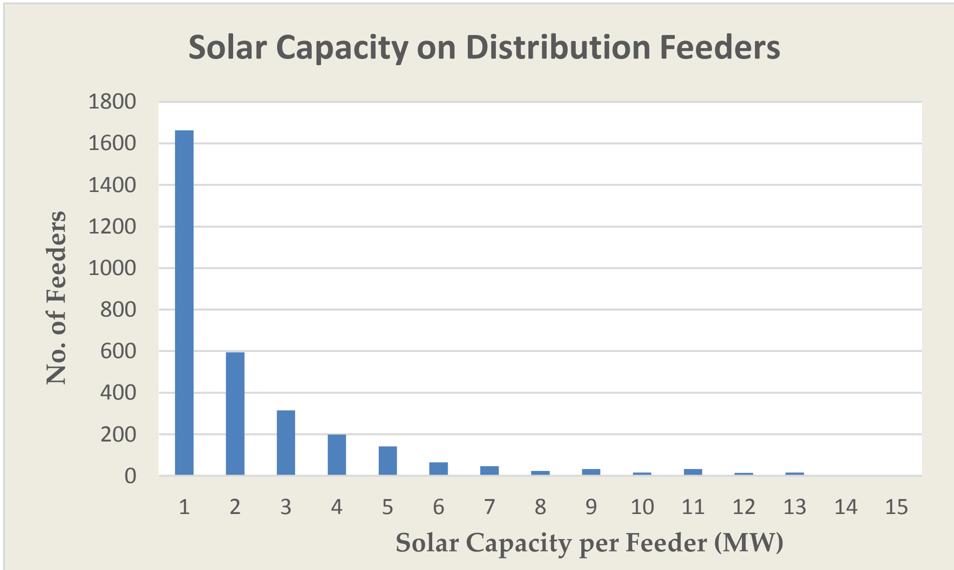


Importantly, PG&E forecasted retail DGPV capacity for each distribution feeder, which enabled evaluation of DGPV costs and benefits for individual feeders and substations. This level of detail ensures increased accuracy and confidence in results, and is an enhancement of the CEC analytical framework that was applied in this study, and well beyond the level of detail and rigor evidenced in prior statewide studies.

To allocate projected retail PV adoption to a distribution feeder, PG&E estimated the probability of a customer investing in PV using multivariate regression analysis in which housing/building and customer characteristics as well as customer usage data were explanatory variables. PG&E then allocated the system level forecast for a given year to the feeders with customers that have the highest probability to adopt.[18] As a result, the amount of DGPV capacity forecasted for each distribution feeder varies significantly throughout PG&E's service territory.[19] Figure 3-2 summarizes the number of feeders based on increasing increments of solar capacity for approximately 3000 distribution feeders where retail and wholesale is forecast to be installed. By 2024, most feeders are forecast to have less than 5 MW of solar DGPV capacity, with the largest number of feeders (about 1650) with 1 MW of less of capacity.

[18] The majority of PG&E's 3,000-plus feeders are assigned some amount of DGPV capacity that varies according to the number of eligible NEM customers and participation factors such as electric usage, total electric bills, income, home value, and other economic drivers.
[19] Because of the amount of variability in DGPV capacity, the ability to evaluate of DGPV impacts at the feeder level enhances the accuracy of study results.

Figure 3-2. DGPV Capacity per Distribution Feeder (2024)



3.2 Wholesale Solar Scenario

PG&E also prepared a wholesale DGPV capacity scenario for years 2015 through 2024. Unlike retail DGPV, PG&E's wholesale DGPV scenario was initially developed only at the system rather than feeder level. Accordingly, Navigant and PG&E developed a methodology to allocate wholesale DGPV capacity first to the county level and then to the feeder level. The wholesale DGPV scenarios examined are summarized in Table 3-2; existing capacity at the end of 2014 is estimated to be 282 MW in PG&E's territory.

Table 3-2. Wholesale DGPV Scenario

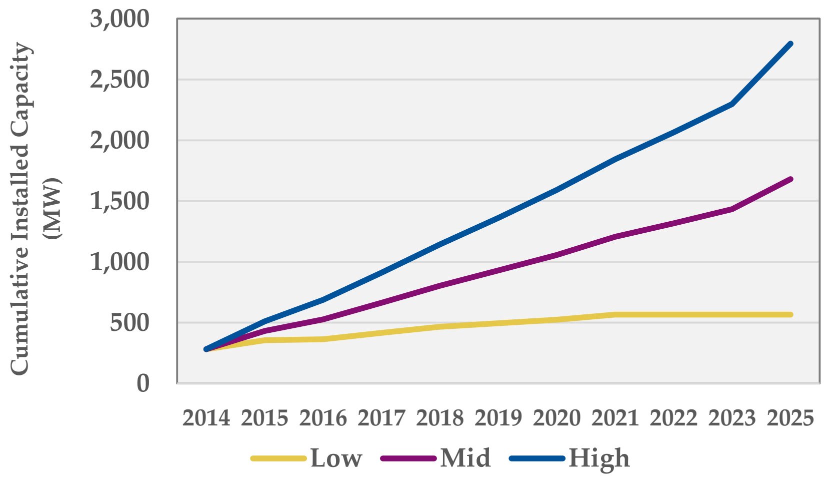
Wholesale Forecast Methodology			
Scenario	Basis of Projection	2015-2024 Incremental Capacity Additions* (MW)	Cumulative Installed 2024* (MW)
Low	Full subscription ("net open positions") under existing CPUC mandated procurement programs (*ReMAT, PV Program, RAM, Green Option Tariff*)	**284 MW**	**566 MW**
Mid	Mid-point between high and low scenarios	**1399 MW**	**1681 MW**
High	"Distributed Solar – PG&E" under the CPUC-mandated '*High DG, 40% RPS by 2024, Mid AAEE*' Planning Scenario for the 2014 LTPP	**2514 MW**	**2796 MW**

Source: PG&E

** Capacity is CEC AC Nameplate capacity.*

Figure 3-3 presents wholesale DGPV capacity for the years 2014 through 2025. Total wholesale capacity ranges from a low of DGPV capacity of well less than 5 percent of the system peak in 2024 to a high of about 10 percent of the 2024 peak. The retail scenarios are combined with wholesale DGPV scenarios to assess total DGPV capacity impacts on a composite basis. Nine DGPV capacity scenarios are analyzed for T&D impacts, representing all possible combinations of retail and wholesale scenarios.[20] It is important to note that the scenarios were developed prior to the evolution of SB 350, which supports increase of the statewide RPS from 33 percent to 50 percent, which may increase the forecast scenarios.

Figure 3-3. Wholesale DGPV Capacity Scenarios



To be consistent with the retail DGPV scenario, Navigant allocated county-level forecasts to the feeder level based on site suitability and availability feeder capacity, described below. Navigant applied a scoring approach that evaluated site suitability for based on 20 criteria, including environmental, public use, customer and building density, terrain, forestation, and other relevant environmental factors. Navigant also considered the level of available hosting capacity when allocating wholesale DGPV to each feeder.

3.2.1 Wholesale DGPV Feeder Allocation

The approach Navigant followed to allocate county-level DGPV capacity is based on land use data and available feeder data to identify locations where larger, wholesale DGPV is most likely to be located. Acceptable land use criterion is essential, as large, ground-based DGPV likely will not receive necessary permits in areas with siting constraints or limitations. Further, developers of wholesale DGPV likely will be discouraged from requesting interconnection if approval is conditioned upon payments for expensive feeder upgrades.

[20] Existing retail and wholesale DGPV capacity is embedded current DGPV feeder loadings.

Steps Navigant followed are summarized below and in detail in subsequent subsections.

- Define an area around each PG&E feeder to enable mapping of wholesale DGPV to the entire PG&E service territory.
- For each feeder area, assess the following two primary factors to rank DGPV attractiveness and resulting allocation to individual feeders. Within each of these two primary factors are about 20 secondary factors that Navigant applied to allocate wholesale DGPV to individual feeders
    1. Land use criteria
    2. Feeder capacity availability

3.2.2 Land Use Criteria

Navigant systematically evaluated feeder suitability via a scoring approach that ranks wholesale DGPV attractiveness based on a range of land use factors, including:

- The area associated with each feeder was mapped using National Land Cover Database (NLCD) classes.
- Each NLCD class was allocated using an attractiveness score based on suitability from a land use perspective.
- The total score for each feeder area was normalized by the feeder area and added to determine the feeder attractiveness score.
- The feeders for each county were ranked based on this attractiveness.
- Forecasted capacity was allocated based on this ranking until the annual capacity for each county was reached.

Upon completion of the land use scoring and ranking process, DGPV attractiveness was further evaluated based on available feeder capacity, described below. Annual adoption for each feeder was based on land use attractiveness and feeder availability using annual blocks of 100 kW to 5,000 kW.

3.2.3 Feeder Capacity Availability

The attractiveness for each feeder was also defined based on available capacity as described below

- A feeder was selected for wholesale DGPV additions only if it had sufficient capacity available to accommodate DGPVs
- The available capacity for each feeder was calculated using a running tally of the existing retail and wholesale DGPV on that feeder. The available capacity was recalculated at the end of each year taking into account new DGPV additions.
- If a feeder reached it maximum capacity, it was not considered for future allocations.
- Forecasted capacity was allocated based on this ranking until the annual capacity for each county was reached.

- Annual capacity was added to each feeder in blocks between 100 kW and 6,000 kW.

In the mid-case scenario, about 1,550 MW is added between 2015 and 2024, mostly in the Central Valley, with some adoption in other counties. Table 3-3 illustrates retail and wholesale capacity additions throughout PG&E's service territory, by division, for the mid-level scenario. Unlike retail DGPV, where most feeders are allocated some DGPV capacity, 10 percent or less of PG&E feeders are projected to be allocated any wholesale DGPV.

Table 3-3. Mid-Case Feeder Level DGPV Capacity by Division

	PV Capacity (MW) - 2024 Mid-Forecast		
DIVISION	**Retail**	**Wholesale**	**Total**
CENTRAL COAST	137	34	171
DE ANZA	247	0	247
DIABLO	376	10	386
EAST BAY	154	0	154
FRESNO	504	444	949
HUMBOLDT	29	0	29
KERN	307	633	940
LOS PADRES	118	13	131
MISSION	246	7	254
NORTH BAY	193	0	193
NORTH VALLEY	233	68	300
PENINSULA	139	9	148
SACRAMENTO	296	27	323
SAN FRANCISCO	85	5	91
SAN JOSE	411	7	418
SIERRA	433	13	446
SONOMA	247	2	248
STOCKTON	98	18	116
YOSEMITE	99	94	193
TOTAL	**4353**	**1385**	**5738**

4. Distribution Impacts

Navigant's analysis of PV impacts over the 10-year horizon is based on detailed load flow simulation studies of representative distribution feeders. Navigant's methodology builds upon the CEC framework, adding greater rigor via use of PG&E studies, detailed PV capacity forecasts, and prior independent research. It includes evaluation of distribution impacts and the associated costs/benefits at the feeder level, using retail and wholesale capacity scenarios described in Section 3.

4.1 Methodology

Navigant's distribution analysis centers on use of industry-accepted models and methods to rigorously assess the impact of PV capacity on distribution feeder performance and reliability. The methodology is consistent with the approaches and assumptions PG&E uses for evaluation of its system for planning, including use of the CYME Distribution Load Flow model to analyze PV impacts.

4.1.1 Study Assumptions and Approach

Key steps and study assumptions Navigant reviewed with PG&E and subsequently applied in its evaluation of DGPV distribution impacts are highlighted below.

- Distribution studies include load flow simulation analysis of representative feeders and verification of the suitability of each representative feeders to evaluate DGPV impacts on PG&E's distribution system
    - Navigant assumed that feeder configurations remain unchanged over 10-year horizon
- The approach for allocating PV capacity for the 20 representative feeders assumes,
    - The location of DGPV capacity on each feeder is based on customer density and amount of load on each feeder segment
    - Distributed small PV is aggregated on feeder line segments at discrete injection points
    - Large (wholesale) DGPV is individually modelled and connected directly to the primary distribution system
    - All feeders within a cluster proportionally allocate PV capacity at the same locations along the feeder
    - DG capacity at individual feeder injection points are increased proportionally in accordance with DGPV retail and wholesale capacity scenarios (*i. e.* CYME models for the representative feeders have the same number of DGPV injections points over the study horizon)
- DG capacity limits are derived based on steady state analysis and
    - The DGPV impact analysis consistent with and based on PG&E planning and operating criteria
    - DGPV capacity is offline or analyzed by distribution operations prior tie transfers to ensure operating limits are not exceeded(e.g., maintenance or main line interruptions)

- o Potential anti-islanding conditions can be mitigated at minimal cost, compliant compliance with IEEE 1547 Guidelines

At the distribution level, DGPV impacts are derived based on analytical studies in accordance with PG&E planning and operating standards and evaluation criteria. Navigant's DGPV distribution system analysis included quantification of steady state impacts associated with the following criteria:

1. Overhead/Underground line/cable loading limits (net loading within normal loading limits)
2. Feeder voltage violations (+/- 5%)
3. Power quality (voltage flicker)
4. Protection system impacts (including mitigation of 2-way power flows, where applicable)
5. Feeder regulator and capacitor operations (operations and maintenance [O&M] or accelerated failure)

In addition to the above, Navigant quantified the cost of DGPV support systems and incremental expenses resulting from the installation of new DGPV capacity for the following, each of which are needed to ensure DGPV installations are properly evaluated and incorporated into day-to-day operations.

1. Distribution Management Systems (DMS) – for DGPV visualization and monitoring
2. Administrative systems and staff support (O&M)

4.2 Representative Feeder Selection

The approach to the distribution impact study is based on the use of a statistically representative feeder sample as a means to assess the benefits and costs of solar PV impacts on PG&E's distribution system infrastructure (all impacts are those that occur within PG&E's service territory). The selection of a representative set of feeders avoids the inherent constraints and inefficiencies associated with the simulation of over 3,000 feeders, while providing a sound basis for predicting system-wide costs. For PG&E, Navigant determined that 20 feeders is sufficient to represent the entire population of PG&E distribution feeders. The methodology Navigant applied and the resulting set of 20 feeders is presented in Appendix A.

4.3 Distribution Simulation Analysis

To quantify costs and benefits resulting from additional DGPV capacity, Navigant conducted simulation studies for each feeder where additional capacity is forecast. These studies focused on steady state impacts; that is, impacts under normal operating conditions.[21] Steady state DGPV impacts are analyzed via a CYME feeder simulation model for each representative feeder. The DGPV distribution system

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[21] DGPV capacity also may result in unacceptable voltage performance under non-steady state conditions, commonly referred to as dynamic or transient analysis, such as rapid voltage rise caused by intermittent solar output due to rapidly moving cloud cover or over-voltages during switching operations. Navigant did not conduct detailed dynamic studies, but relied on prior PG&E studies to assess the conditions under which transient impacts may require mitigation.

impact analysis includes parametric analysis of increasing amounts or PV capacity on the primary distribution system.[22]

Specific steps undertaken to conduct distribution impact analyses included,

- Selection of 20 representative distribution feeders
- Aggregating PV capacity at feeder model nodes or locations based on line segment loading and customer density
- Analyzing impacts via CYME by increasing DGPV capacity from a minimum of 10% to 100% of maximum feeder capacity
- Development of cost equations that predicts interconnection cost as a function of PV capacity over the 10% to 100% range of DGPV capacity for each representative feeder.

Figure 4-1 illustrates the feeder configuration and PV capacity aggregation locations (12 DGPV injection points) for a typical feeder modeled via CYME.

Figure 4-1. Typical CYME Feeder Model PV Locations

Navigant's methodology for predicting DGPV impacts included the evaluation of DGPV on virtually all PG&E distribution feeders, as PG&E and Navigant prepared retail and wholesale PV capacity forecasts

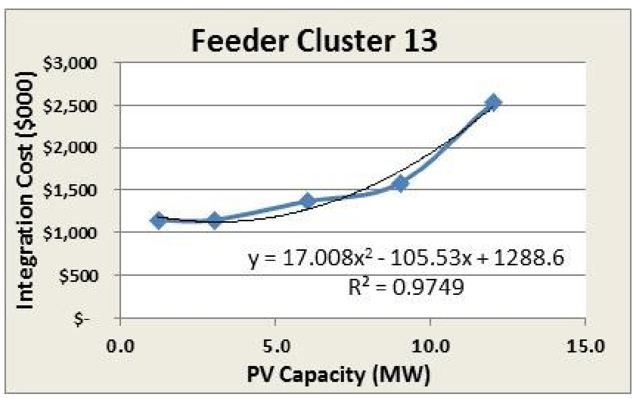
[22] Navigant did not model PG&E secondary (e.g., low voltage lines connected to residential, commercial and smaller industrial customers), as PG&E's CYME model databases do not include secondary lines. This likely under-estimates costs resulting from overloading of secondary lines and transformers. However, Navigant's analysis recognized potential voltage impacts by limiting the amount of voltage variation to slightly less than +/- 5 percent.

for each feeder (approximately 3,000).[23] Since the 20 representative feeder clusters are suitable for evaluating PV impacts for varying levels of capacity for any feeder on PG&E's distribution system, Navigant developed formulas for each representative feeder that predicts the cost of interconnection for increasing amounts of DGPV capacity.

The cost equations were developed by conducting CYME load flow simulation studies for each representative feeder for DGPV capacities from 10 percent to 100 percent of the maximum feeder rating. The point at which DGPV creates voltage, loading or operational violations is the start of the cost curve. Costs are derived based on the cost of mitigating the violation, which typically increases as a function of DGPV capacity. The mitigation and associated costs are described in greater detail in Section 4.4.

Figure 4-2 presents the cost curve and associated equation of best fit for a typical distribution feeder. In this example, the equation for one of the representative feeders (Feeder Cluster 13) is displayed to predict the cost to interconnect PV for each feeder within the cluster; each of which has varying amounts of PV capacity additions over the 10-year study horizon. Of the 20 representative feeders, Navigant determined that18 required upgrades when DGPV capacity is equal to 100 percent of the feeder rating or below. The remaining two did not require upgrades with DGPV capacity set to the feeder maximum rating. The complete set of feeder cost curves and formulas for each cluster appears in Appendix B.

Figure 4-2. Cost Equation for Typical Feeder



4.4 Distribution Upgrades

The cost to accommodate DGPV capacity at the distribution level included substation and feeder upgrades, or, in some cases, new facilities when existing lines and substations are incapable of interconnecting DGPV; mostly high penetration DGPV for the latter. All distribution upgrades were modeled at the primary level, as Navigant did not have sufficient data to predict the cost of line transformer and secondary upgrades.[24]

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[23] There are approximately 3,200 distribution feeders operating at voltages from 4.16kV to 21kV. Approximately 200 feeders are excluded from the analysis for several reasons, including absence of retail customers, lack of suitable wholesale sites, downtown secondary grid or spot network limits, or minimal or no feeder length (feeder backs up adjacent lines at the substation breaker), among other factors.

[24] Nonetheless, Navigant recommends that subsequent studies evaluate line transformer and secondary loadings as PV capacity is added and more data becomes available.

4.4.1 System Impacts

Most candidate distribution upgrades use currently available technology, as enabling technologies at the distribution level will not be commercially available on a wide scale until the latter years of the study. Further, advanced distribution technologies are dependent on availability of high-speed communication systems; the cost of upgrading current communications systems or new systems where none exist today, are currently unknown and therefore are not included in the study. Navigant included passive adjustment of PV inverter power factor for wholesale PV, as is generally recommended as part of PG&E's Interconnection Requirements. It excludes active inverter control for the reasons cited above.

As noted, interconnection costs include support systems and O&M associated with installation of PV capacity. Upgrades to IT support systems, such as CISs and DMSs are also included. The cost of upgrading these systems was based on the amount of additional PV capacity added, recognizing that existing IT support systems will need to be enhanced to accommodate new PV capacity, particularly for high penetration cases that will approach or exceed distribution feeders' loads, resulting in reverse power flows. Specific upgrades include:

- Support systems include upgraded Distribution Management Systems (DMS) and Customer Information Systems (CIS) needed for improved PV visualization, tracking and analysis.
- O&M includes administrative and support staff for the above systems and functions; and increased O&M for new and existing equipment.
- The study assumes that advanced DMS will be needed to monitor, track, and analyze PV operations; including state estimate for switching and other System operations functions - costs may vary based on communications/DSCADA requirements.
- Most cost increases are for retail PV, as wholesale PV (above 1 MW) is required to include SCADA communications.

4.4.2 Mitigation Options

Navigant conducted simulation analyses using CYME to identify the level at which incremental DGPV capacity results in violation of voltage limits, feeder ratings or operation constraints. When violations are identified via the CYME, Navigant selected the lowest cost solution to mitigate the constraint or violation - CYME simulations were performed to determine the applicability and effectiveness of potential solutions. Applicable solutions include those using currently available technology to address voltage, thermal loading, protection and power quality impacts, or violations. No solutions are required for downtown secondary networks in San Francisco and Oakland, as minimal amounts of retail and no wholesale PV is forecast on PG&E's system.

The following options were considered to identify solutions to mitigate impacts and to calculate interconnection costs at the distribution level. These options are typical of those applied by utilities to address steady state or transient impacts. The first two on the list are traditional capacity upgrades, usually through replacement of existing equipment with higher rated devices. The other options address voltage and operational issues such as maintain voltages within limits or improved visualization for higher levels of DGPV capacity. These include the capability to adjust customer-owned PV inverter power factor to 95 percent, leading/lagging (large wholesale PV units only), a no-cost options applied to many feeders.[25]

1. New or upgraded primary overhead/underground line/cables (overloads)
2. New or upgraded substations (including transmission supply lines)
3. Feeder voltage and reactive support (regulating equipment or upgraded lines)
4. Power quality mitigation (voltage flicker)
5. Protection system upgrades (including mitigation of 2-way flows)
6. New communications systems or upgrades
7. New IT systems to monitor and track DG interconnections
8. Operational-related upgrades (improved tie transfers)

Table 4-1 presents the capital cost component associated with the implementation of these mitigation options or impacts.

Table 4-1. Unit Costs – Mitigation Options

Description	Cost ($000)
Reconductor Overhead - 1 Phase (per mile)	$ 250
Reconductor Overhead - 3 Phase (per mile)	$ 500
Capacitor Bank Setting Adjustment	$ 5
New Capacitor Bank	$ 25
Inverter Power Factor Adjustment	$ -
New Distribution Feeder*	$ 1,000
Replace Line Fuse	$ 10
New Recloser	$ 80
New 3 Phase Underground Cable (per mile)	$ 3,000
New Regulator	$ 110
New Substation XFMR Bank	$ 5,000
New Substation	$ 15,000

* Based on cost of new feeder position and one mile of new line

4.4.3 Distribution System Upgrades

Notably, many feeders did not require major system upgrades until PV capacity exceeded 50 percent to 75 percent of the feeder rating.[26] Table 4-2 presents cumulative retail distribution cost by component over the study period for the mid-retail, mid-wholesale PV scenario. Costs are lower in earlier years, an expected result as the cost curves mostly indicate that minimal upgrades are required for low PV

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[25] Setting wholesale PV inverter power factor to 95 leading (absorbing Vars) enabled interconnection of a significant amount of retail and wholesale PV, as many feeders experience high voltages as PV capacity increases. This option avoided more costly upgrades such as line reconductoring or new distribution feeders.

[26] Feeder ratings for the study were set at 4 MVa for 4.16kV, 10 MVa for 12.47kV, 21 MVa for 21kV feeders. There are a relatively small number of 4 kV feeders on PG&E's system.

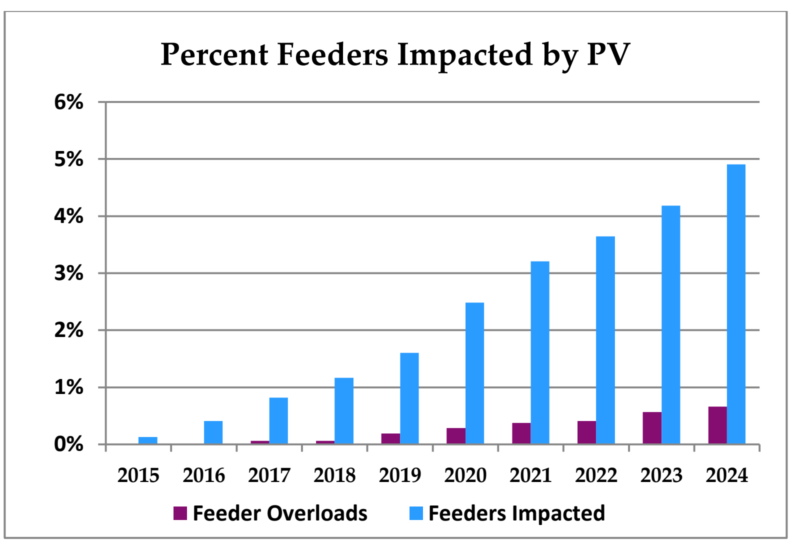
capacity levels. Cost shift upward as capacity additions in later years cause a greater number of impacts requiring mitigation. The highest cost is for capacity upgrades, such as reconductoring lines to relieve lines overloads or to improve voltage performance.

Table 4-2. Distribution System Upgrades (Retail), Mid-Retail, Mid-Wholesale Scenario

Year	DGPV Capacity (MW)			Costs
	Retail	Wholesale	Total	($000)
2015	488	71	559	**$7**
2016	1,103	181	1,284	**$12**
2017	1,578	336	1,915	**$22**
2018	1,965	498	2,463	**$28**
2019	2,355	642	2,997	**$45**
2020	2,749	792	3,541	**$58**
2021	3,138	962	4,100	**$74**
2022	3,538	1,096	4,635	**$90**
2023	3,943	1,237	5,180	**$109**
2024	4,353	1,385	5,738	**$125**

Notably, for each scenario the number of feeders requiring upgrades typically is less than 5 percent to 10 percent of the total number of PG&E feeders. Further, many of the feeders requiring upgrades are those with substantial amounts of wholesale PV capacity, as wholesale PV size and locational impacts are greater than retail PV. Figure 4-3 presents the number of feeders impacted (i.e., requiring upgrades) by PV for the mid-level PV scenario. The total number of feeders requiring mitigation is less than 5 percent in all years; of these, less than 1 percent is due to feeder overloads, which typically are mitigated by installation of new feeders. This percentage could be further reduced if DGPV were optimally located on feeders where impacts are small or non-existent.

Figure 4-3. Feeders Impacted by PV



4.5 Potential DGPV Benefits

Navigant's analysis of benefits potentially derived from solar DGPV focused on distribution and transmission level benefits - primarily deferred capacity and avoided line losses. Navigant's analysis excludes any deferred generation or other potential bulk power system benefits such as regulation, load following, or other production ancillary services, as these benefits are beyond the scope of this study.[27]

4.5.1 Potential Distribution System Benefits

Navigant evaluated the applicability of the following potential distribution benefits:

1. Substation and feeder capacity deferral, including conditions under which firm capacity can be assigned to PV for radial lines and given intermittent output.
2. Reduced equipment and line losses (demand and energy).
3. Improved feeder regulation and power factor (via advanced inverter control).
4. Enhanced reliability and security.

All benefits evaluated are those that directly impact the utility; no external, customer, or societal benefits are assigned in the analysis. The primary distribution benefits considered include deferred feeder and substation capacity, line and equipment losses, reliability, and voltage benefits. Of these, deferred capacity offers the greatest benefits opportunity.

Navigant's evaluation of potential distribution benefits is described below. Where applicable, distribution benefits are quantified and compared to the cost of distribution upgrades.

Distribution Capacity Deferral

The dominant benefit associated with PV is distribution capacity deferral. Navigant quantified capacity deferral benefits using methods comparable to those used by PG&E planning.[28] Potential distribution capacity benefits were evaluated for each substation and feeder; approximately 800 and 3,100, respectively. The first step entailed preparation of a capacity load balance prior to PV connection to identify the timing and magnitude of annual capacity surpluses or deficits. A capacity benefit was assigned when the amount of firm PV capacity exceeded feeder or substation capacity deficits. These deficits occur when feeder load growth causes total load to exceed feeder or substation capacity ratings, and therefore require capacity upgrades. Solar DGPV potentially can defer the capacity upgrades if the amount of firm solar exceeds the capacity deficit. The duration of the capacity benefit ranged from one to 20 years, recognizing that load growth could exceed the amount of firm PV capacity added each year. The assessment of firm PV capacity available was based on the ELCC factor provided for each feeder.[29] The average ELCC assigned to solar DGPV on individual distribution feeders and substation

[27] The study also does not quantify the costs and benefits associated with inter-utility or interstate bulk power transfer, although transmission studies confirm that constraints and adjustments in flows are likely to impact power sales transactions.

[28] Navigant sought to replicate the processes PG&E uses in its distribution capacity planning process, including load and capacity balances used to determine when additional distribution capacity is required.

[29] PG&E performed ELCC studies and provided values used in this study.

transformers deferred ranged from 0.30 to 0.40.[30] The ELCC's for solar on each feeder were provided by PG&E. The approach PG&E applied to derive ELCC's on radial distribution feeders is derived based on the statistical likelihood that DGPV capacity will be available during the highest loading hours (as opposed to the generation system, which is based on composite loss-of-load expectation (LOLE) on the networked system)

On average, PG&E upgrades 10 to 12 distribution feeders and 7 to 10 substation transformers banks annually, thereby representing the total population of potentially deferrable assets. Additionally, one new substation is installed every 5 to 10 years. These quantities reflect PG&E planning criteria and practices, which include load transfers to maximize utilization of existing assets and minimize cost. The number of feeders deferred due to PV connections ranged from a low of three to a high of 26 annually over the 10-year planning horizon; corresponding to low-retail and wholesale scenarios, and high-retail and wholesale scenarios, respectively. A maximum of two substation transformer banks are deferred annually (high PV scenario), a small number due to the relatively small number of substation capacity upgrades and the low amount of firm solar capacity, either retail or wholesale.

Navigant determined that distribution capacity deferral potential was limited by the large number of feeders and substations that experience early evening peaks in summer; a very small percentage of feeders have mid-day peaks, and, of these, most are winter peaking in the San Francisco area where solar capacity forecasts are lower. Accordingly, solar capacity on most feeders were found to have relatively low ELCC's and therefore low firm capacity relative to maximum PV output. Thus, DGPV would have to be over-sized in these locations to effect deferral, which likely would be uneconomical from a benefits perspective. Figure 4-4 confirms most PG&E feeders peak between hour-ending 6 p.m. and 7 p.m. during the summer including those near capacity ratings, while less than 10 percent peak during hours when PV output is highest.

[30] ELCC is expected to drop significantly under a 50 percent RPS scenario. Thus, the ELCC estimates in this study are on the high side and overstate benefits in later years.

Figure 4-4. Feeder Versus PV Hourly Profiles

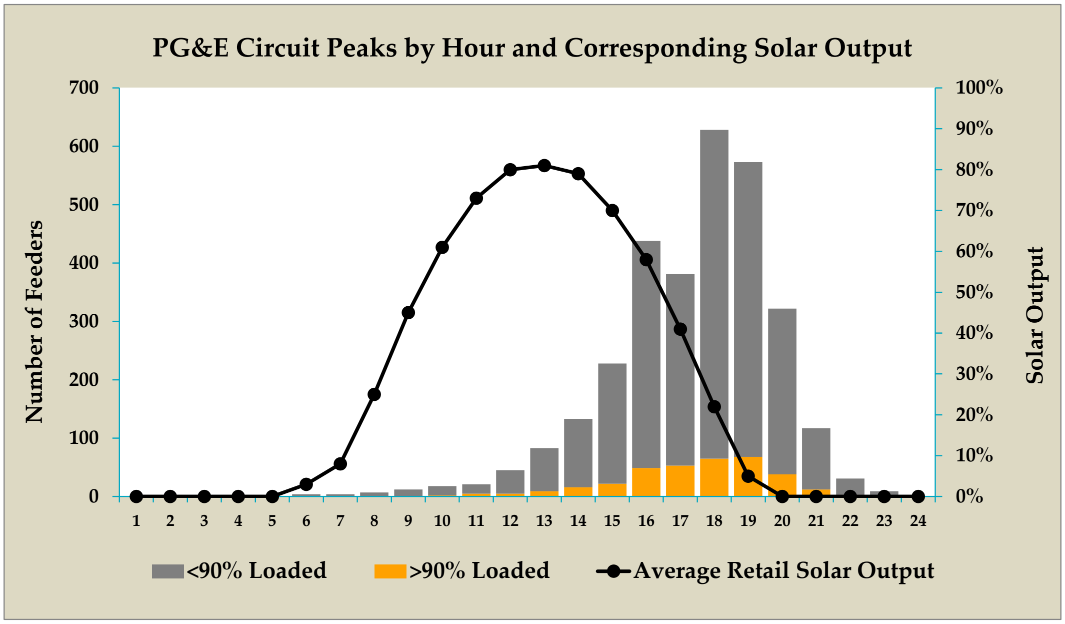


Table 4-3 presents the number and percentage of feeders deferred for the mid-capacity PV scenario based on the above factors and criteria. In earlier years, the number of feeders deferred is minimal, as the amount of firm PV capacity at peak is insufficient to effect a deferral. However, as greater amounts of PV capacity are added, the number of deferrals increases, up to approximately 30 percent on a cumulative basis.[31] The feeder ELCCs for the combined set of feeders ranges between 30 percent and 40 percent for feeders that have been deferred, which corresponds to feeders that mostly experience mid-day peaks.

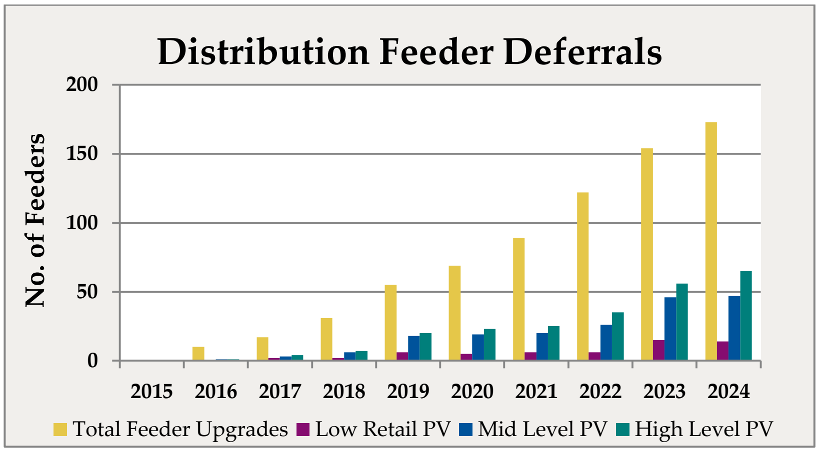
Table 4-3. Distribution Feeder Deferral – Mid-Retail, Mid-Wholesale Scenario

Year	Cumulative PV Installed (MW)	No. of Feeders Eligible for Deferral	Cumulative Feeders for Deferral	No. of Feeders Deferred by PV	Cumulative Feeders Deferred (%)
2015	539	0	0	0	0%
2016	1,233	10	10	1	10%
2017	1,826	7	17	3	18%
2018	2,344	14	31	6	19%
2019	2,863	24	55	18	33%
2020	3,397	14	69	19	28%
2021	3,938	20	89	20	22%
2022	4,450	33	122	26	21%
2023	5,115	32	154	46	30%
2024	5,654	19	173	47	27%

[31] The number of feeder deferrals in the table summarizes the *total* number of feeder deferrals each, which include deferrals from prior years. For example, PV may be able to defer distribution capacity upgrades for one or more years and typically do not result in a permanent deferral over time. Hence, the actual number of deferrals do not correlate exactly to the Column labeled "No. of Feeders Eligible for Deferral" or on a cumulative basis.

Figure 4-5 presents feeder deferrals for low and high-retail scenario, in addition to the baseline case. The low-retail scenario results in few feeder capacity deferrals due to the limited available firm PV capacity. The high-retail scenario results in a modest increase, as the high-retail PV scenario is relatively close to the baseline scenario.

Figure 4-5. Distribution Feeder Deferral – All Scenarios



Note: All scenarios are based on a mid-level wholesale PV scenario

<u>Reduced Equipment and Line Losses</u>

The results of the distribution simulation studies indicate losses are low at low levels of PV penetration, and generally increase at higher PV penetration, particularly on feeders where PV capacity exceeds feeder load. Further, on many feeders, total energy deliveries increase due to voltage rise caused by connected PV, particularly on end-of-line sections where voltages increase above levels measured at the substation bus. For these reasons, Navigant concluded that, on average, any increase or decrease in line loss would offset. This reasoning tends to understate cost for higher PV capacity cases where net line losses often are higher.

<u>Enhanced Reliability</u>

Absent enhanced smart technologies not generally available today or the foreseeable future, enhanced reliability stemming from PV, an intermittent resource, is very limited. The presence of PV capacity will not reduce the frequency of customer interruptions, nor will it reduce the duration of interruptions. It is possible to reduce the duration of interruptions via automated transfer schemes, where greater amounts of load could be transferred to unfaulted line sections; however, this scheme is feasible only for highly automated transfer schemes with centralized intelligent systems that monitor, track, and control DG. These schemes generally are not available today.

Power Quality

Active voltage support from PV inverters is anticipated over the next several years, but not implemented today beyond pilot evaluations.[32] Navigant included in its evaluation passive voltage support from PV inverters, described earlier, where overvoltage conditions are mitigated via power factor adjustments, thereby avoiding more costly upgrades such as line reconductoring and voltage regulating devices.

4.6 Summary of Distribution Impacts

The evaluation of DGPV impacts on PG&E's distribution system is supported by a rigorous set of distribution simulation analyses using analytical tools that PG&E applies for its internal studies. The level of detail of the analysis, which includes evaluation of distribution impacts on an individual feeder basis. These methods contrast those used in other studies, which often are based on avoided cost projections developed independent from solar DGPV studies, and importantly, do not capture the locational and feeder-specific impacts obtained from an analysis of specific feeders and the integrated network.

Table 4-4 presents cumulative distribution costs and benefits (retail only) for the mid-retail, mid-wholesale scenario, including net costs on a total and unitized basis. Results indicate minimal benefits in early years (compared to cost); however, benefits increase in later years as opportunities for capacity deferral increase, thereby offsetting some of the costs required for interconnection.

Table 4-4. Distribution Costs and Benefits

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	**559**	$7	$0	**$7**	$14	$8
2016	1,103	181	**1,284**	$12	$0	**$11**	$10	$6
2017	1,578	336	**1,915**	$22	$1	**$21**	$13	$8
2018	1,965	498	**2,463**	$28	$2	**$27**	$14	$8
2019	2,355	642	**2,997**	$45	$4	**$41**	$17	$10
2020	2,749	792	**3,541**	$58	$8	**$51**	$18	$11
2021	3,138	962	**4,100**	$74	$11	**$63**	$20	$11
2022	3,538	1,096	**4,635**	$90	$15	**$76**	$21	$12
2023	3,943	1,237	**5,180**	$109	$22	**$87**	$22	$13
2024	4,353	1,385	**5,738**	$125	$30	**$95**	$22	$13

Results for the low and high DGPV capacity scenarios appear in Appendix D.

Related findings and key results include:

1. The impact of DGPV capacity at lower capacity levels is modest, with interconnection costs below $100 million in 2019 for the base case scenario. Total costs increase to over $300 million in 2024 for the base line scenario (5,738 MW total, 1385 MW wholesale, 4353 retail DGPV).

[32] The CPUC Rule 21 Working Group has addressed requirements associated with the implementation of local and centralized active inverter control. Inverter technology is capable of providing voltage support via adjustable power factors. Underwriter Laboratories is expected to approve enhanced inverters within the next year or two.

2. Although wholesale DGPV capacity is much lower than retail, the impact and cost of interconnecting wholesale DGPV is greater than retail by a factor of approximately three to one.
3. The primary benefit of DGPV is deferred capacity. However, the value of deferred capacity is limited due to the non-alignment of solar mid-day peak output versus transmission and distribution peaks, which occur mostly during late afternoon or early evening hours.
4. Most system upgrade costs are socialized under current NEM policy, although this study confirms costs tend to be localized among a small percentage of distribution feeders. The ability to direct customers to install DGPV on feeders with significant integration capacity would mitigate potential cross subsidies, as would policies that encourage customers to limit their exports to the grid
5. Gross distribution-related benefits for DGPV could increase through application of policies and/or complementary technologies that align system performance with grid needs.

5. Transmission System Analysis

At the transmission level, Navigant's analysis addresses steady state DGPV impacts on the interconnected network, including interties. The objective of the analysis is to assess the impact of retail and wholesale DGPV addition on PG&E's network for the years 2015 through 2024. These impacts include upgrades or changes in operating procedures that may be required to accommodate increasing amounts of solar capacity. It also identifies transmission deferrals achieved by displacement of load by solar. The analysis excludes impacts of solar additions outside of PG&E's service territory and potential impacts of new solar within PG&E's network on other utility systems.

5.1 Methodology

5.1.1 Study Assumptions

Navigant's analysis of DGPV impacts follows the approach used by PG&E in its internal studies, including assumptions and forecasts outlined in the California Independent System Operator's (CAISO's) most recent Transmission Plan. All analyses are based on the regional 2024 Positive Sequence Load Flow (PSLF) Transmission model.[33] Independent of new DGPV additions, the model database includes the following committed and proposed upgrades and changes within the PG&E network:

- New generation and transmission projects or upgrades
- Generation retirements and re-ratings
- Adjustments to intertie path flows

5.1.2 Modeling Approach

The approach to DGPV modeling and resource adjustments for PG&E's bulk system included selection of model parameters and modifications to reflect, to the extent possible, likely actions system operators would undertake to ensure reliability and performance is maintained. Accordingly, the following steps and actions were taken in structuring PSLF load flow cases for each DGPV capacity scenario.

1. Using a generation dispatch priority list (provided by PG&E), systematically take conventional generating units offline in amounts equal to new solar DGPV capacity
2. Adjust remaining online generators to operate at less than maximum load when needed to maintain area voltage or normal or post-contingency support
3. Adjust voltage/reactive resources to maintain voltages at desired levels
4. Add new voltage control devices, where required, to maintain voltage schedules
5. Apply a phased approach to systematically remove existing PG&E generation from service while integrating increasing amounts of solar DGPV

[33] All transmission studies were based on the 2024 network model, as it impractical and unnecessary to conduct a year-by-year analysis. The impact of DGPV capacity for all scenarios and years is thus based on the 2024 model.

6. Adjust system swing buses to improve PSLF solution performance, where required
7. Conduct normal and contingency load flow simulations based on PG&E contingency schedules (lines subject to n-1 and n-2 single and common-mode failures)
8. Identify least-cost mitigation option to address violations or constraints

The following steps describe the technical analysis used to assess DGPV impacts.

1. Create base case model (PSLF Network Load Flow) of PG&E's transmission system
   - Western Electric Coordinating Council (WECC) full-loop base case model was used for the study, confirm base model results with PG&E Transmission Planning
2. Map DGPV capacity mapped to low-voltage transmission buses
   - Solar DGPV scenarios, by feeder, used to map DGPV capacity to transmission substations
   - Update model to include future utility-scale DGPV, wind and combined heat and power (CHP) (2024 model)
3. Evaluate and verify steady state load flow results and transmission performance
   - System peak load with DGPV output adjusted for the time of the system peak
   - Peak solar output (not coincident with the feeder peak)
4. Conduct load flow contingency analysis
   - Normal, first and second contingencies consistent with PG&E & CAISO criteria
   - Evaluate bus voltages, line and equipment overloads, and intertie power transfers, real and reactive
   - Identify mitigation options to address constraints and violations
   - Determine incremental loss savings for solar DGPV

5.1.3 Mitigation Options

The following options were consider to mitigate the impact of solar DGPV additions for normal and contingency loading and voltage violations.

- For transformers overloads
  - Upgrading the cooling equipment to improve the rating
  - Upgrading limiting terminal equipment to improve the rating
  - Installation of new transformers
  - Installation of a parallel transformer adjacent to existing transformers
- For transmission circuits overloads or voltage violations
  - Upgrading the limiting circuit element
  - Reconductoring the entire line
  - Installation of automatic sectionalizing equipment

    - Construction of new parallel circuits
- For generator step-up (GSU) overloads
    - Relocation of DG interconnection to the high side to alleviate overloads
    - Contingency thermal overloads and voltage concerns
- For voltage violations
    - Shunt capacitors or reactors
    - Synchronous condensers
    - STATCON, SVC

Energy storage is not directly considered as a solution as the analysis excludes energy savings and other non-T&D benefits; however, storage should be considered as an alternative to the above mitigation options to address normal or contingency loading or voltage violations.[34] Similarly, automatic load shedding or special protection schemes (SPSs), such as transfer tripping, are excluded as each potentially degrades system reliability or performance.[35] Subsequent studies that evaluate the applicability of SPS may identify specific locations where SPS is suitable.

5.2 Transmission Impact Studies

Navigant followed accepted industry practices to evaluate the impact of DGPV on PG&E's transmission system. All results are based on load flow analysis using the PSLF network model, with model databases corresponding to CAISO's and PG&E's most recent forecast of generation and transmission additions or retirements. It also includes known large renewables scheduled or proposed over the study timeframe. Impacts are evaluated both during the system peak (late afternoon) and at the time of the DGPV peak (noon to 2 p.m.). The average PG&E system load at the time of peak DGPV output is approximately 74 percent.

5.2.1 Normal and Contingency Analysis

Navigant conducted PSLF load flows analyses under normal and contingency conditions, consistent with methods and assumptions used by PG&E and CAISO. It includes impacts within PG&E's service territory, excluding impacts on neighboring systems and balancing areas except for intertie transfer, presented in the following section. It includes a network model and large renewable forecast based on the most current WECC and CAISO base model for 2024.

This research presents transmission study results for three DGPV penetration scenarios outlined in Section 2:

1) Low-Retail, Low Wholesale DGPV
2) Mid retail, Mid-Wholesale DGPV

[34] Energy storage may be able to address dynamic impacts, including transient voltages resulting from highly variable solar output. Dynamic impacts were not addressed in this study.
[35] SPS may be considered as an alternative to system upgrades when PG&E or CAISO studies support SPS as a viable alternative; however, the analysis required to make this determination is beyond the scope of this study.

3) High retail, High Wholesale DGPV

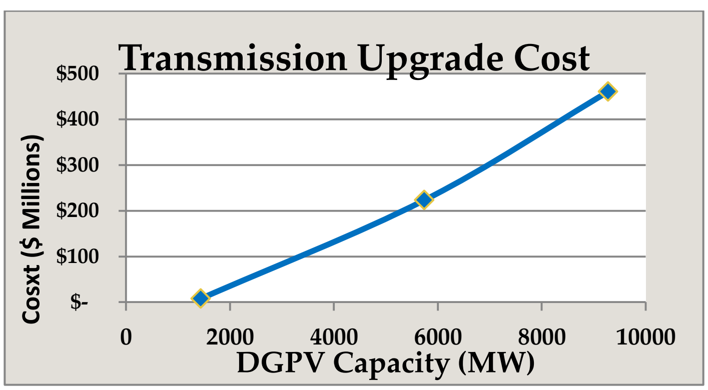
Results indicate that few violations occur for the low DGPV case. As DGPV capacity increases, most violations are line or equipment overloads, virtually all on lower voltage lines rated 115kV and below. For lower and moderate capacity forecasts, DGPV capacity can be interconnected with nominal system upgrades. The primary enhancement includes reconductoring of overloaded 70kV and 115kV lines. Several B (n-1) contingencies could potentially be addressed by adjusting post-contingencies generation outputs as opposed to construction of new or upgraded lines and substations, but are beyond the scope of the subject study.

5.2.2 System Costs

All loading and voltage impacts are mitigated by identifying the lowest cost system upgrade capable of addressing the issue. Congestion management, which system operators may use to mitigate impacts via generation re-dispatch, was not considered due to the uncertainty as to whether each scheme would ensure transmission system reliability or performance would not be compromised. Navigant recognizes that congestion management may be a cost-effective choice to address contingency overloads or overvoltage; but additional analysis beyond the scope study would be needed. Further, it would require a determination as to whether CAISO congestion management procedures could be applied to DG-level solar.

Due to the significant time and effort needed to conduct comprehensive transmission studies, including contingency analysis of all relevant single and double contingencies, load flow studies were limited to the three cases presented in Figure 5-1. These cases provide a sufficient spectrum of outcomes to reasonably predict transmission impacts over the complete range of retail and wholesale DGPV capacity scenarios. Figure 5-1 presents transmission upgrade cost as a function of DGPV capacity. The cost of the transmission upgrades are based on per unit costs used in recent transmission planning studies.

Figure 5-1. Transmission Cost Curve



Note: Cost of transmission upgrades is zero below 1500 MW

An equation for the above cost curve is used to predict transmission upgrade costs for all retail and wholesale DGPV capacity scenarios. All impacts are due to line and equipment overloads caused by DGPV capacity additions. It includes both normal and contingency overloads, as well as shunt capacitors for voltage support in the Mendicino and Pease 60kV areas. Results are presented in Section 5.3.

Table 5-1 presents cumulative transmission costs for capital upgrades for the mid-retail capacity cases. Costs in earlier years are low, but rises once incremental DGPV capacity exceeds 1,500 MW. In later years, the cost of transmission upgrades approaches the cost of distribution upgrades; for example, mid-retail, mid-wholesale distribution capacity upgrades (Table 4-2) is $290 million in 2024 versus $217 million for transmission. Results for the low- and high-retail DGPV scenarios appear in Appendix C.

Table 5-1. Transmission Costs: Mid-Retail Cases

Year	Total PV Capacity (MW)			Transmission Cost ($ Millions)		
	Low Wholesale	Mid Wholesale	High Wholesale	Low Wholesale	Mid Wholesale	High Wholesale
2015	559	559	559	$0	$0	$0
2016	1,184	1,284	1,385	$0	$1	$5
2017	1,710	1,915	2,123	$18	$27	$36
2018	2,145	2,463	2,782	$37	$51	$65
2019	2,562	2,997	3,433	$55	$75	$96
2020	2,982	3,541	4,100	$74	$101	$129
2021	3,412	4,100	4,787	$95	$129	$164
2022	3,813	4,635	5,457	$114	$156	$201
2023	4,218	5,180	6,145	$135	$186	$241
2024	4,627	5,738	6,852	$156	$217	$284

5.2.3 Transmission Interties

Although Navigant's evaluation excludes impacts on adjacent systems and production costs (energy and capacity), it is instructive to assess how DGPV capacity may impact key interties. Table 5-2 presents potential DGPV capacity constraints or limits on three key interfaces under high DGPV capacity scenarios. Path 66 is the California-Oregon Interface (COI), Path 26 is the southern interface with California Edison where flows are predominantly southern, and Path 15 is an internal PG&E path, where flows are predominantly northern.

Table 5-2. Transmission Intertie Flows

Description	CAISO 2014-2015 Base Case	High DGPV Base Case w/ 9300 MW DGPV*
Load	29,167	21,680
Generation	28,358	25,480
Path 66 (+ is N-S)	4,799	1,232
Path 15 (+ is S-N)	260	-1,400
Path 26 (+ is N-S)	2,045	3,835

Results for the high DGPV scenario indicate COI flows could be significantly curtailed during periods of maximum DGPV output, resulting in potentially uneconomic flows and transactional economic lost opportunities[36]; up to 3,500 MW of North-South transfers potentially could be constrained. Navigant

[36] COI transfers include purchases of up to 4,800 MW low-cost hydroelectric capacity from Northwest sources.

anticipates that lost opportunity transactions could be substantial and should be assessed if DGPV capacity creates intertie constraints.

Similarly, Path 15 flows could reverse by up to 1,400 MW. Navigant did not evaluate the capability to accommodate the shift in flows northward. Path 26 to SCE exhibits similar shifts in flows, with a potential increase in southern flows of up to 1,800 MW for maximum DGPV output.

5.3 Transmission Benefits

5.3.1 Benefit Categories

Navigant evaluated the applicability of the following transmission benefits:

1. Reduced Transmission line and equipment losses
2. Substation and line capacity deferral
3. Reduced grid congestion
4. Improved power factor & voltage regulation

5.3.2 Reduced Transmission Line and Equipment Losses

The installation of DGPV capacity provides incremental loss benefits at the transmission, particularly during daytime hours when DGPV output is highest. To identify the amount loss reduction associated with varying levels of DGPV capacity, Navigant conducted load flow analysis for DGPV capacity forecasts ranging from low to high. The load flow studies include use of the 2024 model database to reflect future system upgrades. The model load was adjusted to 74 percent of the 2024 peak to align with the mid-day maximum DGPV output (the PG&E peak occurs in later hours when DGPV output is lower). Table 5-3 presents loss analysis results, indicating incremental loss reduction ranges from about zero for the low DGPV scenario to a high of 2.75 percent for the mid-level scenario. Loss reductions decline to 2.31 percent for the high DGPV scenario. Given the range of loss reductions, Navigant assigned 2 percent loss reduction for all DGPV penetration levels in the benefits analysis. A 20 percent loss factors is used to derive energy loss savings.

Table 5-3. Transmission Losses

Description	PGE System Load (MW)	Scaled Load (MW)*	Low DGPV Scenario (MW)	Mid-DGPV Scenario (MW)	High DGPV Forecast (MW)
Load (MW)	29297	21680	21290	21576	21680
Losses (MW)	980	805	812	647	590
DGPV Capacity	-	0	1435	5738	9300
Loss Reduction	-	0	-7	158	215
Percent Reduction	-	-	**-0.49%**	**2.75%**	**2.31%**

5.3.3 Capacity and Other Transmission Benefits

Similar to distribution, transmission capacity benefits also are limited, as most transmission upgrades are needed for reliability, security, or generation delivery (including large renewable capacity), and therefore, cannot be deferred.[37] Where upgrades are required due to load growth—mostly lower voltage 115 kV and below—there is insufficient firm DGPV capacity available to affect a deferral. This finding is largely due to low DGPV output at the time of the system peak, which occurs later in the day for virtually the entire network. The amount of DGPV capacity in the mid-coastal area, which peaks mid-day, is insufficient to defer proposed investments. Transmission load flow results also did not indicate any instances where congestion relief was mitigated. In addition, most transmission investments are needed for reliability, security, and generation interconnection as opposed to load growth, thereby proving few opportunities for capacity deferral. Most transmission capacity deferral opportunities are for lower voltage assets (i.e. below 230kV) that serve load centers. However, the absence of alignment of transmission peaks with peak solar output essentially eliminates capacity deferral.[38] As noted in Section 5.2.3, high amounts of DGPV capacity creates intertie constraints, which likely would result in higher cost due to lost opportunities for interstate power sales transactions.

5.4 Summary

Navigant evaluated transmission impacts for low, mid, and high DGPV capacity forecasts via PSLF network load flow simulation analyses of the PG&E system within service territory boundaries. Impacts are limited to transmission assets only, excluding impacts to adjacent utility systems and generation located within and outside of the balancing areas for PG&E service territory.[39] It includes a network model and large renewable solar capacity additions based on the most current WECC and CAISO base model for 2024.

For lower and moderate capacity scenarios, DGPV capacity can be interconnected with nominal system upgrades. The primary enhancement includes reconductoring of overloaded 70 kV and 115 kV lines. Several B (n-1) contingencies could potentially be addressed by adjusting post-contingencies generation outputs as opposed to construction of new or upgraded lines and substations, but are beyond the scope of the subject study.

Table 5-4 presents cumulative retail transmission costs and benefits for the mid-retail, mid-wholesale DGPV scenario. Results confirm transmission impacts and interconnection costs are very low in earlier years when DGPV capacity is low, but increases in later years as transmission impacts become more prevalent. All benefits in the table are associated with line loss reduction, as there are no capacity deferral opportunities for the reasons described above.

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[37] The CAISO Regional Transmission Plan presents system upgrades proposed on the PG&E system, most of which are needed for non-load related purposes.
[38] Targeted programs that include incentives for solar to located in constrained areas could support transmission capacity deferrals; however, the study does not include solar incentives or other mechanisms to constrained areas.
[39] Navigant recognizes the impact of DGPV on generation scheduling, ancillary services, regulation requirements, and intertie transfers can be significant from an energy production cost perspective, particularly for high DGPV penetration cases that require shut down or curtailment of generation unit output. Navigant did not quantify these impacts, as the primary objective of the study is to identify T&D costs and benefits.

Table 5-4. Transmission Costs and Benefits, Mid-Retail, Mid-Wholesale Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	181	1,284	$1	$1	($0)	($0)	($0)
2017	1,578	336	1,915	$22	$2	$20	$13	$7
2018	1,965	498	2,463	$40	$2	$38	$19	$11
2019	2,355	642	2,997	$59	$3	$56	$24	$14
2020	2,749	792	3,541	$78	$4	$74	$27	$15
2021	3,138	962	4,100	$98	$5	$94	$30	$17
2022	3,538	1,096	4,635	$119	$5	$114	$32	$18
2023	3,943	1,237	5,180	$141	$6	$135	$34	$20
2024	4,353	1,385	5,738	$165	$7	$157	$36	$21

The complete set of retail transmission costs and benefits for the low and high DGPV scenarios appears in Appendix D.

Related study transmission findings include the following:

- Few impacts were identified on network transmission rated 230 kV and above. None require mitigation or upgrades.
- Several of the contingencies potentially could be mitigated by SPSs, but were not considered viable as these may degrade transmission reliability or performance. SPSs may be deemed viable where detailed studies determine they can be implemented without negatively impacting the transmission network.
- There are significant shifts in intertie flows for high DGPV capacity scenarios; particularly on Path 66 (~ 2,500 MW reduction in flows between Oregon and California) and up to an 1,800 MW increase on Path 26 south to SCE. This is presented in the following table for high DGPV penetration. Although these findings may have significant cost implications, the impacts are not quantified as they are associated with wholesale energy sales.
- Similar to distribution, the transmission system peak occurs during early evening hours, which limits potential transmission capacity deferral benefits; the primary benefits is an average incremental line reduction of 2 percent.

For subsequent studies, it may be appropriate to conduct dynamic stability analysis for contingencies that exhibit signs of or appear susceptible to large and rapid voltage swings.

Table 5-5. Transmission Violations & Mitigation

(All Violations Highlighted in Red)

Division	Contingency Description	Post Low	Post Mid	Post High	Mitigation	Cost ($MM)	Low	Mid	High
Humboldt	Humboldt Bay - Humboldt No.1 115 kV and Humboldt Bay-Humboldt No.2 60 kV Lines	0.995	1.02	1.066	Reconductor Humboldt Bay-Humboldt #1 60kV line.	$8	$0	$8	$8
Sacramento Valley	Cottonwood #4 230/115 kV Transformer	0.615	0.96	1.093	Replace Cottonwood #3 230/115kV bank.	$10	$0	$0	$10
Sierra	Higgins - Bell 115 kV Line	0.879	0.911	1.193	Reconductor Drum-Rio Oso #1 115kV line.	$52	$0	$0	$52
Sierra	Higgins - Bell 115 kV Line	1.051	1.063	1.247	Reconductor Drum-Rio Oso #2 115kV line.	$52	$0	$52	$52
Stockton/ Stanislaus	Stanislaus-Melones-Manteca No.1 115 kV & Stanislaus-Manteca No.2 115 kV Lines	0.651	0.807	1.15	Reconductor Stanislaus-Melones-Riverbank Jct 115kV line.	$6	$0	$0	$6
Stockton/ Stanislaus	Stanislaus-Manteca No.2 115 kV & Stanislaus-Melones-Riverbank Jct 115 kV Lines	0.911	1.019	1.157	Reconductor Stanislaus-Melones-Manteca #1 115kV line.	$12	$0	$12	$12
Fresno/ Yosemite	Base system (n-0)	0.784	0.807	1.065		$12	$0	$0	$12
Fresno/ Yosemite	Base system (n-0)	0.513	0.419	1.692	Reconductor Borden-Coppermine 70kV line	$12	$0	$0	$12
Fresno/ Yosemite	Base system (n-0)	0.843	0.582	1.863	Reconductor Borden-Coppermine 70kV line	$12	$0	$0	$12
Fresno/ Yosemite	Base system (n-0)	0.923	0.66	1.937	Reconductor Borden-Coppermine 70kV line	$12	$0	$0	$12
Kern	Base system (n-0)	0.376	0.386	1.204	TBD		$0	$0	$0
Kern	Base system (n-0)	0.508	0.517	1.145	TBD		$0	$0	$0
Kern	Base system (n-0)	0.107	0.11	1.077	Reconductor Taft-Elk Hills 70kV line.	$7	$0	$0	$7
Kern	Base system (n-0)	0.151	0.671	1.103	Reconductor Midway-Taft 115kV line.	$24	$0	$0	$24
Kern	Base system (n-0)	0.276	0.276	1.192	Reconductor Arco-Carneras 70kV line	$12	$0	$0	$12
Kern	Base system (n-0)	0.121	0.12	1.033	Reconductor Arco-Carneras 70kV line	$12	$0	$0	$12
Kern	Fellows-Midsun 115 kV Line	0.169	0.902	1.595	Reconductor Midway-Taft 115kV line.	$24	$0	$0	$24
Kern	Fellows-Midsun 115 kV Line	0.278	0.779	1.441	Reconductor Midway-Taft 115kV line.	$24	$0	$0	$24
Kern	Midway-Taft 115 kV Line	0.204	1.041	1.865	Reconductor Midway-Midsun 115kV line.	$25	$0	$25	$25
Kern	Midway-Taft 115 kV Line	0.205	1.042	1.865	Reconductor Midway-Midsun 115kV line.	$25	$0	$25	$25
Kern	Midway-Taft 115 kV Line	0.181	0.901	1.580	Reconductor Midsun-Fellows 115kV line.	$11	$0	$0	$11
Kern	Midway-Taft 115 kV Line	0.278	1.375	2.410	Reconductor Midsun-Fellows 115kV line.	$11	$0	$11	$11
Kern	Midway-Taft 115 kV Line	0.565	1.573	2.096	Reconductor Fellows-Taft 115kV line.	$13	$0	$13	$13
Kern	Midway-Taft 115 kV Line	0.538	1.491	1.985	Reconductor Fellows-Taft 115kV line.	$13	$0	$13	$13
Kern	Midway-Taft 115 kV Line	0.309	1.212	1.701	Reconductor Fellows-Taft 115kV line.	$13	$0	$13	$13
Central Coast/ Los	Coburn-Oil Fields #2 60 kV	0.820	1.150	1.090	Reconductor Coburn-Oil	$18	$0	$18	$18

Division	Contingency Description	Post Low	Post Mid	Post High	Mitigation	Cost ($MM)	Low	Mid	High
Padres					Fields #1 60kV				
Central Coast/ Los Padres	Coburn-Oil Fields #1 60 kV	0.833	**1.166**	**1.109**	Reconductor Coburn-Oil Fields #2 60kV	$18	$0	$18	$18

6. Economic Analysis

6.1 Overview

Navigant's study quantifies T&D costs and benefits for each scenario for increasing amounts of DGPV capacity. Both T&D costs and benefits are derived via detailed simulation methods and databases that PG&E uses for its own studies. All technical studies and costs were reviewed by PG&E T&D engineering and planning for accuracy and consistency.

6.2 Methodology

Cumulative net costs were derived by combining annual transmission and distribution system costs and benefits from Sections 4 and 5 for each retail and wholesale DGPV scenario. The mid retail and mid wholesale case is deemed the baseline scenario, with all low and high scenarios presented as sensitivity cases. All costs are in 2015 dollars, escalated at a real escalation factor of 2 percent for most cost categories. Most costs and benefits are one-time capital investments. However, expense-related impacts such as increased O&M due to intermittent solar and additional PG&E staffing required for administrative support and distribution operations also are included in the economic analysis. All results are presented in total cumulative dollars and dollars per MWh. DGPV utilization factors of 20 percent and 24 percent are assigned to retail and wholesale DGPV, respectively.

Cumulative net costs are presented on a combined basis and separately for retail and wholesale DGPV. Navigant allocated costs between retail and wholesale DGPV proportionally based on the amount of retail versus wholesale capacity on each feeder. Total annual interconnection costs is calculated for each feeder based on the cost formulas presented in Section 3. These costs are then allocated to retail and wholesale components based on the ratio of retail and wholesale DGPV to total installed capacity. Transmission costs are allocated annually based on the ratio of the total retail and wholesale capacity installed system-wide to the total amount of DGPV installed on the PG&E system – no adjustments are made to account for locational transmission upgrades as most transmission upgrades are on the network system and therefore, not easily assigned to retail or wholesale DGPV. Similarly, retail and wholesale DGPV benefits are derived based on ratio of total annual installed solar capacity.

6.3 Benefit/Cost Analysis

Navigant derived cumulative net T&D value for each retail and wholesale DGPV capacity scenario. Nine cases are analyzed by varying baseline retail and wholesale DGPV capacity scenarios based on low, mid, and high capacity scenarios presented in Section 3. Table 6-1 summarizes composite DGPV capacity scenarios for each of the nine cases where benefit costs analyses were conducted over the 10-year study horizon (WHDGPV designates wholesale DGPV capacity).

Table 6-1. Combined Retail and Wholesale DGPV Capacity Scenarios

Year	Low retail DGPV Scenario (MW)	Mid retail DGPV Scenario (MW)	High retail DGPV Scenario (MW)

	Low WHDGPV	Mid-WHDGPV	High WHDGPV	Low WHDGPV	Mid-WHDGPV	High WHDGPV	Low WHDGPV	Mid-WHDGPV	High WHDGPV
2015	159	159	159	559	559	559	559	559	559
2016	278	378	480	1,184	1,284	1,385	1,184	1,284	1,385
2017	383	588	796	1,710	1,915	2,123	1,886	2,091	2,299
2018	496	814	1,133	2,145	2,463	2,782	2,645	2,962	3,281
2019	604	1,039	1,475	2,562	2,997	3,433	3,377	3,812	4,248
2020	726	1,284	1,844	2,982	3,541	4,100	4,103	4,662	5,221
2021	892	1,579	2,266	3,412	4,100	4,787	4,859	5,547	6,234
2022	1,046	1,867	2,689	3,813	4,635	5,457	5,583	6,405	7,227
2023	1,229	2,191	3,155	4,218	5,180	6,145	6,313	7,275	8,240
2024	1,435	2,545	3,659	4,627	5,738	6,852	7,053	8,163	9,277

All T&D net cost studies include the combined impacts of retail and wholesale DGPV.[40] Typically, retail DGPV is far much diverse from a locational standpoint, as it is installed commensurate with the number of residential and commercial customers across each feeder. Wholesale DGPV is much larger, which results in greater mitigation requirements and interconnection cost. Accordingly, results are broken out by retail and wholesale components (Section **Error! Reference source not found.**) to capture the locational impacts of retail DGPV, which is smaller and more distributed on distribution feeders, versus larger DGPV, which typically is less distributed and located at fewer sites along feeders.

6.3.1 Baseline Retail DGPV Scenario

Table 6-2 presents cumulative net retail cost of T&D system upgrades for the mid-retail and wholesale scenario (i.e., the baseline DGPV scenario). Results indicate annual costs exceed savings, with net costs ranging from $6 million in 2015 to just above $250 million cumulatively by 2024 for the high-retail scenario.[41] When cost is unitized as a function of DGPV energy production, cost per MWh ranges from $7/MWh in 2015 to $33/MWh in 2024 for the mid retail and mid wholesale scenario.

Table 6-2. Mid Retail, Mid Wholesale DGPV Scenario

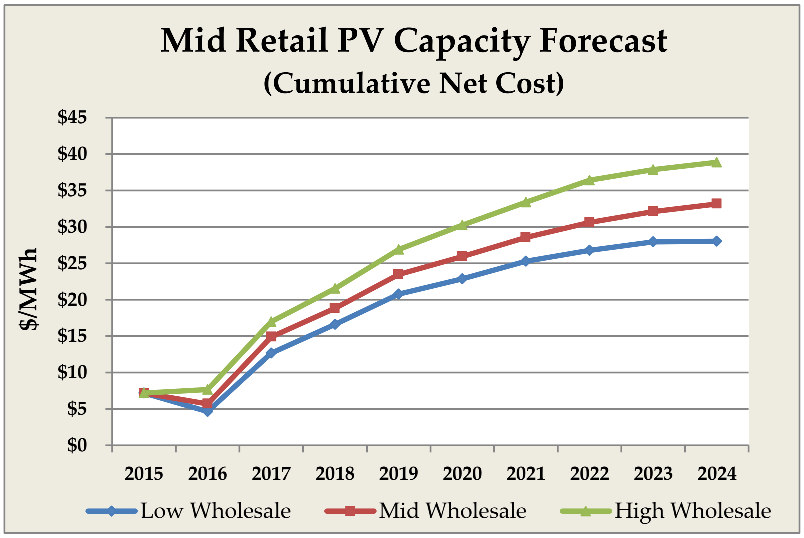
Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	**559**	$7	$1	$6	**$13**	**$7**
2016	1,103	181	**1,284**	$13	$2	$11	**$10**	**$6**
2017	1,578	336	**1,915**	$44	$3	$41	**$26**	**$15**
2018	1,965	498	**2,463**	$69	$4	$65	**$33**	**$19**
2019	2,355	642	**2,997**	$104	$7	$97	**$41**	**$23**
2020	2,749	792	**3,541**	$136	$11	$125	**$45**	**$26**
2021	3,138	962	**4,100**	$172	$15	$157	**$50**	**$29**
2022	3,538	1,096	**4,635**	$210	$20	$190	**$54**	**$31**

[40] However, all costs in Sections 6.3.1 and 6.3.2 are for the retail component of total interconnection cost. Section **Error! Reference source not found.** presents cumulative costs for both retail and wholesale components combined.
[41] The amount of wholesale DGPV for each retail DGPV forecast in the table is 1,385 MW in 2024.

2023	3,943	1,237	**5,180**	$250	$28	$222	**$56**	**$32**
2024	4,353	1,385	**5,738**	$290	$37	$253	**$58**	**$33**

Figure 6-1 illustrates variances in T&D interconnection cost for the mid retail DGPV scenario as a function of wholesale DGPV capacity. Unitized costs vary from about $28/MWh to $38/MWh by 2024 for the low and high wholesale DGPV scenarios, respectively, indicating wholesale DGPV capacity has a significant impact on cost despite relatively modest increases in total connected DGPV capacity.

Figure 6-1. Mid Retail DGPV, Wholesale DGPV Sensitivity Analysis



6.3.2 Sensitivity Analysis

Sensitivity analysis is performed for the low- and high retail DGPV capacity scenarios, including varying wholesale DGPV capacity for each retail case. It also includes a case under the assumption that customers are incented to install DGPV at feeders where solar capacity impacts are small. The distribution studies confirm that most DGPV impacts occur on a relatively small number of feeders – less than 10 percent of feeders are impacted – suggesting policies and practices that promote DGPV in locations with minimal impact would reduce net costs.

6.3.2.1 Low Retail DGPV Scenario

Figure 6-3 presents cumulative net retail cost of T&D system upgrades for the low retail and wholesale scenario. Similar to the baseline scenario, annual costs exceed savings, with net costs ranging from $1 million in 2015 to $55 million cumulatively by 2024 for the low retail scenario.[42] When net cost is unitized as a function of DGPV energy output (on a per MWh scale), it ranges from $8/MWh in 2015 to $27/MWh in 2024. Costs are slightly higher in later years compared to baseline scenarios as the higher cost to interconnect wholesale DGPV, on average, drives net costs upward.

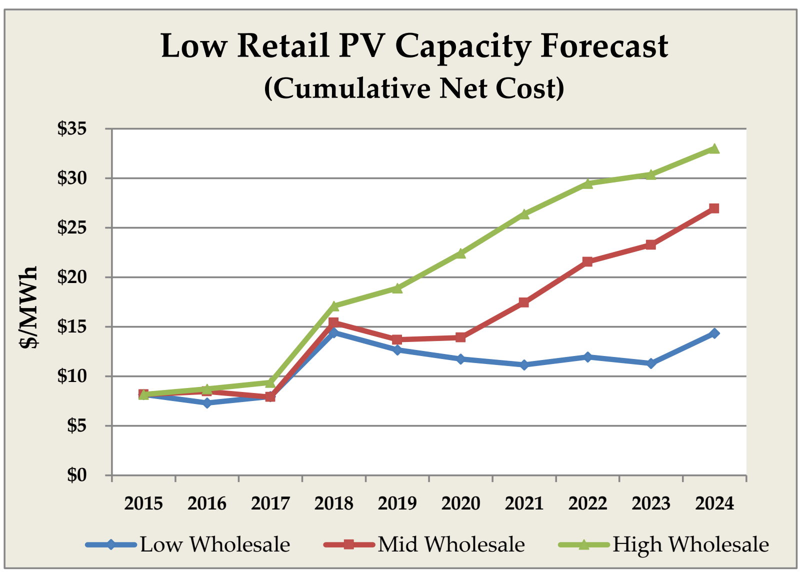
[42] The amount of wholesale DGPV for each retail DGPV forecast in the table is 1,385 MW in 2024.

Table 6-3. Low Retail, Mid Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	**159**	$1	$0	$1	$14	**$8**
2016	197	181	**378**	$3	$0	$3	$15	**$8**
2017	252	336	**588**	$4	$0	$3	$14	**$8**
2018	316	498	**814**	$9	$0	$9	$27	**$15**
2019	397	642	**1,039**	$11	$1	$10	$24	**$14**
2020	493	792	**1,284**	$14	$2	$12	$24	**$14**
2021	617	962	**1,579**	$21	$2	$19	$31	**$17**
2022	771	1,096	**1,867**	$32	$3	$29	$38	**$22**
2023	954	1,237	**2,191**	$44	$5	$39	$41	**$23**
2024	1,160	1,385	**2,545**	$62	$7	$55	$47	**$27**

Figure 6-2 illustrates variances in cumulative cost for the low retail DGPV scenario as a function of incremental wholesale DGPV capacity.[43] Unitized costs vary from about $15/MWh to $33/MWh by 2024 for the low and high wholesale DGPV scenarios, respectively. Similar to the baseline analysis, wholesale DGPV capacity has a significant impact on net cost. The low wholesale case produces lower net cost due to the lower amount of total incremental DGPV capacity versus the mid-wholesale and high-wholesale scenarios (1,435 MW incremental cumulative DGPV capacity for the low scenario versus 2545 MW and 3659 MW for the mid and high scenarios, respectively, in 2024).

Figure 6-2. Low Retail DGPV, Wholesale DGPV Sensitivity Analysis



[43] All case studies are based on impacts of new, incremental DGPV capacity. The impacts of existing retail and wholesale DGPV are excluded from scenario analysis.

6.3.2.2 High Retail DGPV Scenario

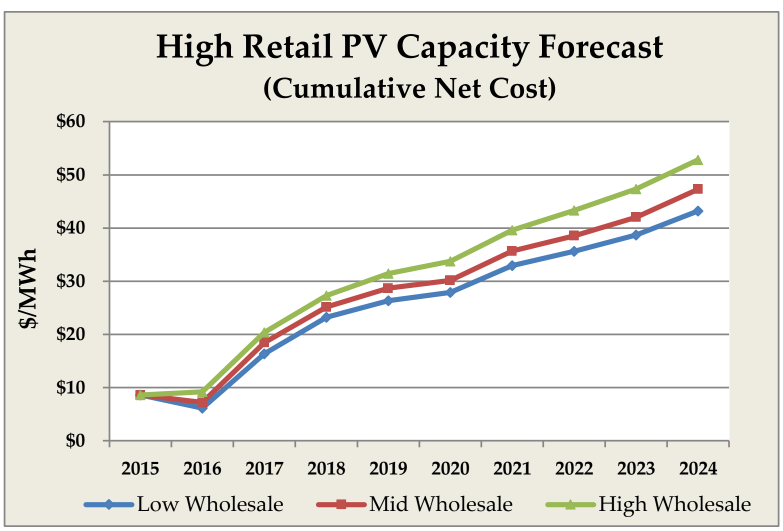
Table 6-4 presents cumulative net cost of T&D system upgrades for the high-retail and mid wholesale scenario (i.e., the baseline DGPV scenario). Similar to baseline scenario, annual costs exceed savings, with net costs ranging from $7 million in 2015 to $562 million cumulatively by 2024 for the high-retail scenario.[44] On a per MWh scale, cumulative net cost ranges from $9/MWH in 2015 to $47/MWH by 2024. Costs are slightly higher in later years compared to baseline scenarios as the higher cost to interconnect retail *and* wholesale DGPV, on average, drives net costs upward.

Table 6-4. High Retail, Mid Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	**559**	$8	$1	$7	$15	$9
2016	1,103	181	**1,284**	$15	$2	$14	$13	$7
2017	1,755	336	**2,091**	$60	$3	$57	$32	$18
2018	2,464	498	**2,962**	$114	$5	$109	$44	$25
2019	3,170	642	**3,812**	$169	$10	$159	$50	$29
2020	3,870	792	**4,662**	$220	$15	$204	$53	$30
2021	4,585	962	**5,547**	$307	$21	$287	$62	$36
2022	5,308	1,096	**6,405**	$387	$28	$359	$68	$39
2023	6,038	1,237	**7,275**	$485	$40	$445	$74	$42
2024	6,778	1,385	**8,163**	$615	$54	$562	$83	$47

Figure 6-3 illustrates variances in net retail interconnection cost for the high retail DGPV scenario as a function of wholesale DGPV capacity. Unitized costs for 2024 vary from about $42/MWh to $52/MWh for the low and high wholesale DGPV scenarios. Unlike the baseline analysis, wholesale DGPV capacity has a lower, but not insignificant impact on net cost, as higher retail penetration results in higher net costs for all wholesale DGPV scenarios.

Figure 6-3. High Retail DGPV, Wholesale DGPV Sensitivity Analysis



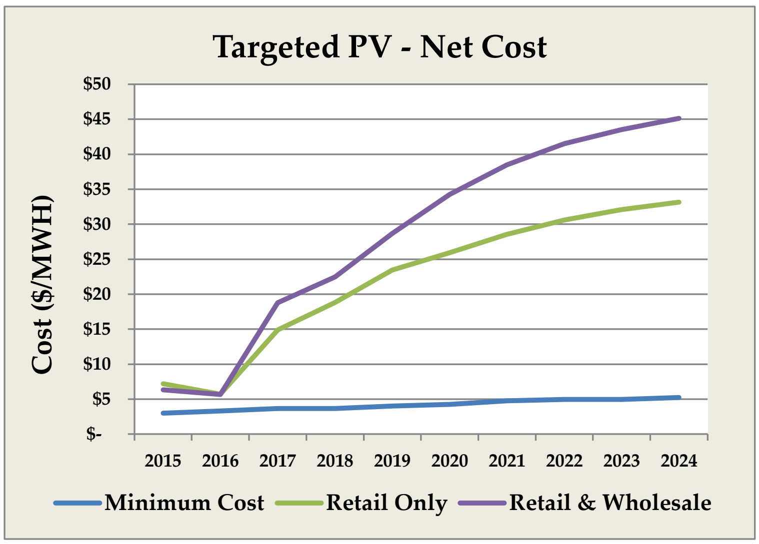
[44] The amount of wholesale DGPV for each retail DGPV forecast in the table is 1,385 MW in 2024.

A complete set of tables presenting cumulative retail costs and benefits for all DGPV scenarios for the years 2015 through 2024 is included in Appendix D.

6.3.3 Targeted DGPV

Navigant explored a minimum cost scenario ("Targeted DGPV") where the underlying assumption is that customers are somehow incented to locate DGPV in areas where impacts are lower, or technology solutions such as energy storage can be used to mitigate impacts. Figure 6-4 presents the results of a targeted scenario where proactive measures are taken to reduce DGPV interconnection costs. For the minimum cost case, marginal net cost to interconnect DGPV is estimated to be $5/MWh or lower for all years of the study. The targeted scenario is well below the mid-retail-only, and combined mid-retail and mid-wholesale, where cumulative net cost is $33 per MWh and $45/MWh, respectively.

Figure 6-4. Targeted DGPV Scenario



6.4 Summary

Table 6-2 presents cumulative net retail cost of T&D system upgrades for the mid-retail and wholesale scenario (i.e., the baseline DGPV scenario). Results indicate annual costs exceed savings, with net costs ranging from $6 million in 2015 to just above $250 million cumulatively by 2024 for the high-retail scenario.[45] When cost is unitized as a function of DGPV energy production, cost per MWh ranges from $7/MWh in 2015 to $33/MWh in 2024 for the mid retail and mid wholesale scenario.

The retail cost component of interconnection costs is presented separately from wholesale to identify the net cost of DGPV to inform NEM pricing recommendations. Retail interconnection costs range from $6 million in 2015 to $253 million in 2024. Transmission costs are allocated equally to retail and wholesale DGPV based on the relative amount of DGPV capacity, as it was not realistic nor necessary to allocate transmission costs by location. Among other factors, the operation of the transmission system in a network configuration obviates the need to allocate costs to specific locations.

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[45] The amount of wholesale DGPV for each retail DGPV forecast in the table is 1,385 MW in 2024.

Other high-level observations from the study include:

- Results indicate the costs of distribution upgrades associated with interconnecting DGPV are significantly higher than benefits. The primary reason for this finding is due to minimal alignment of solar versus feeder peaks, which reduces potential capacity benefits.
- Higher retail penetration significantly increases unit and total net cost. Low retail capacity results in minimal interconnection cost, as they capacity is "spread" over many feeders, thereby mitigating impacts. However, with higher retail penetration, up to 4,000 MW or greater by 2024, feeder impacts are more dominant.
- Distribution upgrade costs are concentrated in a few key circuits with high DGPV penetration (typically less than 10 percent of feeders require upgrades). This finding is driven by wholesale DGPV capacity, which is located on a smaller subset of feeders with greater associated impacts.
- Most system upgrade costs are socialized under current NEM policy, although this study confirms costs tend to be localized among a small percentage of distribution feeders. The ability to direct customers to install DGPV on feeders with significant integration capacity would mitigate potential cross subsidies, as would policies that encourage customers to limit their exports to the grid
- Gross distribution-related benefits for DGPV could increase through application of policies and/or complementary technologies that align system performance with grid needs.
- For lower and moderate capacity scenarios, DGPV capacity can be interconnected with nominal transmission system upgrades. Few impacts were identified on network transmission rated 230 kV and above. None require mitigation or upgrades.
- There are significant shifts in intertie flows for high DGPV capacity scenarios; particularly on Path 66 (~ 2,500 MW reduction in flows between Oregon and California) and up to an 1,800 MW increase on Path 26 south to SCE. Although these findings may have significant cost implications, the impacts are not quantified as they are associated with wholesale energy sales.

7. Appendix A: Representative Feeder Selection Methodology

Navigant's approach for selecting representative feeders for PG&E's distribution system (approximately 3,000 feeders) is described below.

Background

Navigant applied the feeder sampling results presented herein to perform the solar DGPV analysis and to develop a scenario analysis tool that PG&E can use in future studies.[46] The overarching goal of the analysis was to produce results that are relevant to and implementable in PG&E's distribution planning processes and activities.

Methodology

Navigant's objective was to identify a set of feeders suitable not only for solar PV, but for a broader set of DER, to allow for an accurate and efficient evaluation of the impact of DGPV deployment across the system. Navigant selected a set of 20 representative feeders based upon a systematic examination of PG&E's feeders with respect to a broad ranging set of parameters that reflect the diversity of PG&E's system.[47]

Feeder Sample Review

Navigant used a standard k-means clustering to develop an operationally representative sample of PG&E's feeders based on the weighting parameters listed below[48] It includes assigned weighting factors that recognizes certain attributes have greater significance and impacts on feeder performance.

[46] Navigant recognizes that results of the analyses are of interest to several potential outside stakeholders in addition to PG&E's distribution and transmission planning staff, the primary audience of the report.
[47] The feeder selection process recognizes PG&E's desire to include representative feeders that are equally suitable for use in the solar DGPV study and other DER technologies, efficiency and demand response programs.
[48] The feeder selection methodology applied in the December 2012 study and Navigant's DGPV analysis each are based on a statistical approach developed in the early 1980's and subsequently applied by utilities and industry analysts. Further reference on the foundation and methodology to this approach is described in the research paper, "A Cluster-Based Method of Building Representative Models of Distribution Systems," H. L. Willis H. N. Tram, and R. W. Powell, IEEE Transactions on Power Apparatus and Systems, March 1983, p. 1776.

Feeder Selection: Weighting Factors

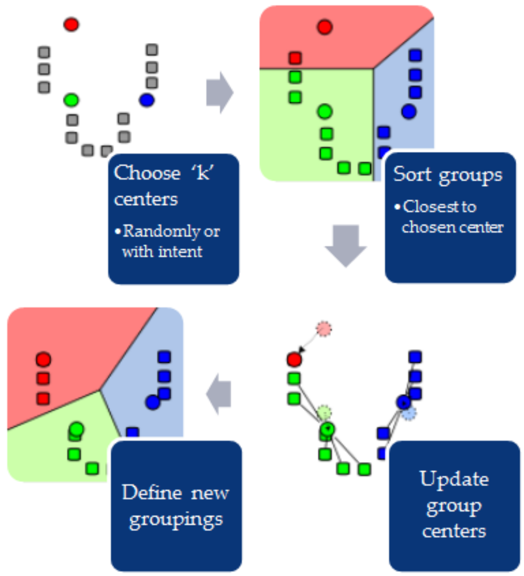
9x Weight	4x Weight	1x Weight
Voltage	# Fixed Capacitors	OH Main Line Miles
Total Miles	# Switched Capacitors	UG Main Line Miles
# **Domestic Customers**	# OH TR	
# **Industrial Customers**	# UG TR	
Fixed Capacitors kVAr	# Agricultural Customers	
Switched Capacitors kVAr	# Other Customers	
# **Voltage Regulators**	PV NBM Capacity (kW)	
2010 Load (kW)	Non-PV Capacity (kW)	
	Average DR Impact (kW)	

Updated Representative Feeder Sample

Navigant performed k-means clustering for the updated representative set by using the original set of 20 feeders as seed (initial) representatives. The clustering algorithm used to select representative feeder seeks to define a number of fixed subsets of feeders in the entirety of PG&E's system. The profile of the representative feeder selected for each of the defined subsets is the one that best represents a larger set of feeders with common attributes in PG&E's system. For example, one feeder may represent the 24 kV distribution feeders that are relatively long, have high PV penetration, and a large number residential customers. A graphical depiction of the feeder selection algorithm is presented below.[49] The process outlined in the illustration is repeated until differences in feeder groupings (clusters) are sufficiently small to justify selection of a representative set of feeders to represent the entire set of distribution feeders.

[49] The algorithm was implemented using Microsoft VBA, as several iterations are required to group feeders into clusters with common attributes and to identify the feeder that best represents the cluster.

Graphical Depiction of K-Means Algorithm



Source: Navigant Consulting, Inc.

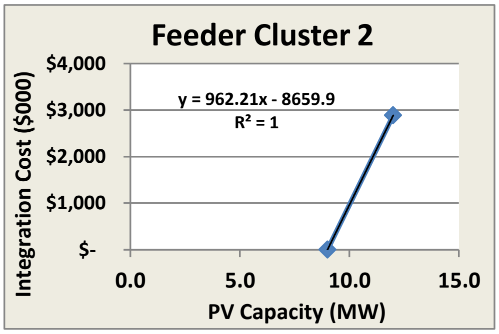
Summary

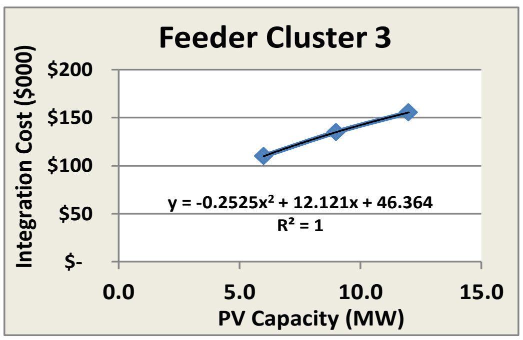
The final set of 20 representative feeders were determined to be suitable by PG&E for CYME simulation analysis in terms of availability of operational CYME data sets and status. The final set appears in the following table, which includes key feeder attributes and properties both for the new representative feeders and those that remain from the original set.

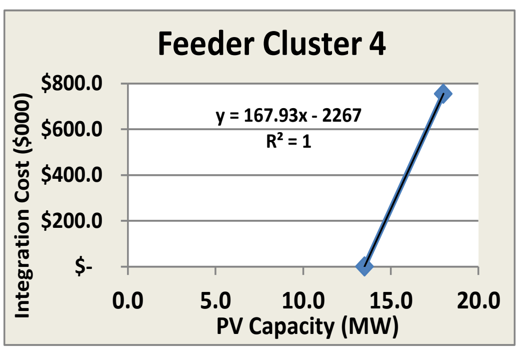
Table 7-1. Representative Feeder Profiles

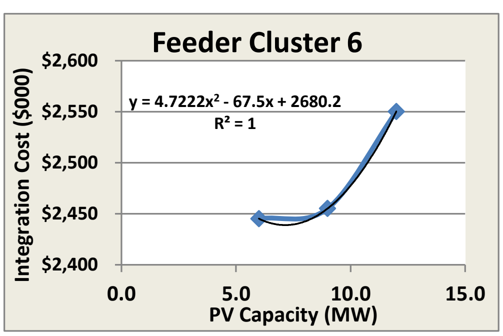
Grp ID	No. of Fdrs	kV	Total Mi	Res	Com	Ind	Fixed Cap kVar	Swd Cap kVar	OH +UG Regs	2010 Load (kW)	# Fixed Cap	# Switched Cap	OH TR	UG TR	Agr	Oth	Non-PV (kW)	PV NBM (kW)	AVG DR Impact (kW)	OH Main Line Mi	UG Main Line Mi
1	114	21	40	1165	127	45	308	3579	1	364	0	3	120	100	17	6	120	471	254	4	4
2	103	12	49	4850	338	61	1200	4699	0	343	1	5	278	131	9	19	32	578	147	7	3
3	211	12	22	1085	155	44	255	3827	0	354	0	4	118	57	7	7	87	313	167	4	2
4	146	21	61	3446	342	96	424	8054	1	337	0	6	212	243	12	15	108	1122	331	7	5
5	171	12	31	563	82	19	378	2178	1	136	0	2	140	27	31	4	208	191	141	4	1
6	147	12	83	297	61	9	788	4075	3	364	1	5	282	19	111	4	37	392	148	12	0
7	57	12	65	869	69	13	654	3668	1	755	1	4	326	62	4	3	1	437	154	8	1
8	115	12	22	847	282	96	884	5254	0	301	1	5	111	74	7	11	76	398	229	5	2
9	201	12	30	372	56	13	88	1199	1	388	0	1	113	21	23	4	153	130	72	3	1
10	99	12	52	2499	485	95	552	4488	1	328	1	5	307	114	17	16	77	503	182	6	2
11	224	12	37	2958	195	40	291	2950	1	269	0	3	185	113	9	10	36	478	144	5	3
12	279	12	142	1659	199	21	256	3256	6	318	0	5	744	68	38	6	7	516	167	11	1
13	50	12	123	618	93	15	2535	6382	6	356	3	7	470	31	208	3	74	575	250	16	0
14	121	12	35	1629	170	44	2341	5459	1	359	2	5	184	76	17	9	79	367	230	6	2
15	112	21	59	2672	229	68	2745	9085	0	366	2	7	223	180	21	11	151	937	288	9	4
16	128	18	261	2453	332	40	893	6374	10	307	1	7	1309	107	141	11	320	812	463	22	1
17	65	12	158	1060	148	19	558	6240	7	220	1	8	712	59	229	4	59	967	256	16	1
18	157	12	43	2272	187	44	470	6890	1	324	1	7	240	114	19	9	81	607	246	7	2
19	125	4	7	714	62	9	228	511	0	423	1	2	58	6	0	3	1	81	22	1	1
20	176	4	8	951	68	8	266	584	0	213	1	2	70	6	0	4	1	85	25	2	1

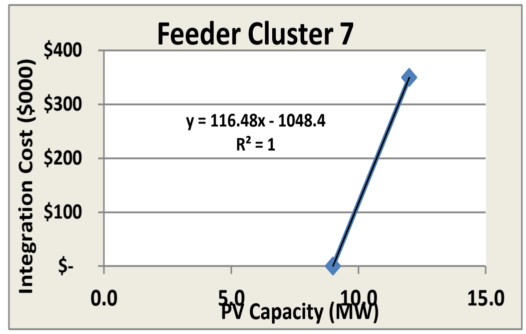
8. Appendix B: Representative Feeder Cost Formulas

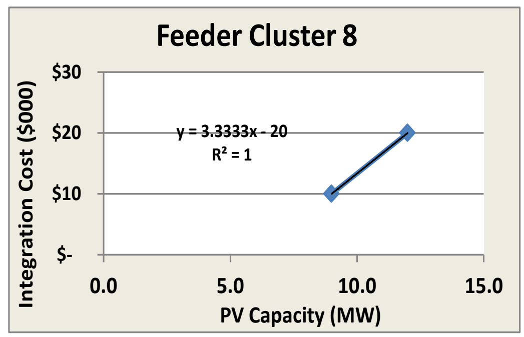


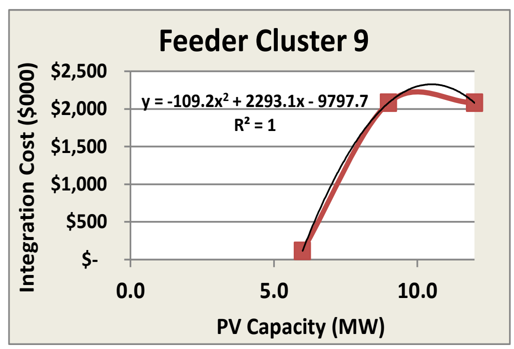


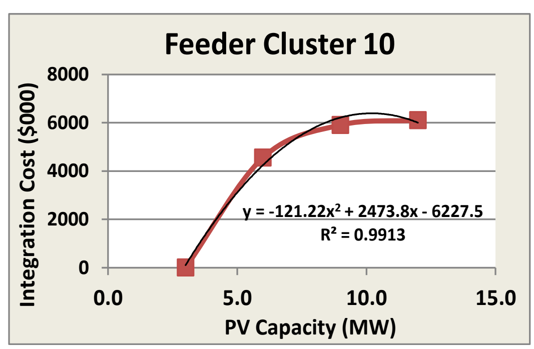


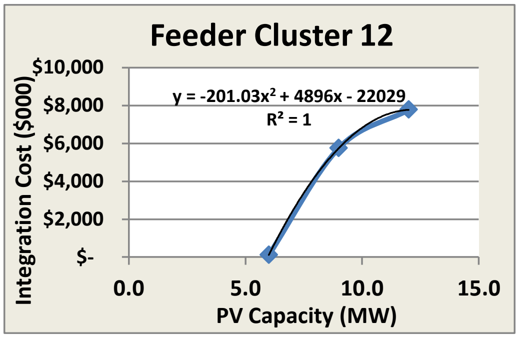


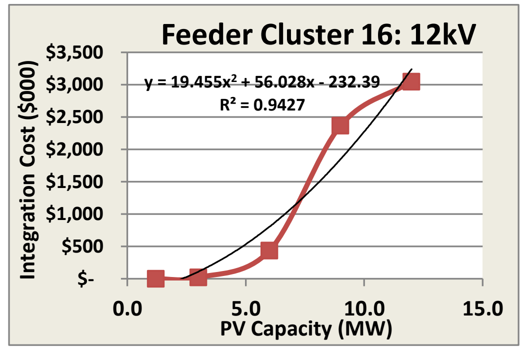


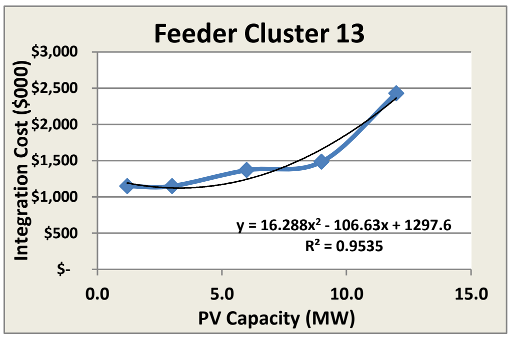


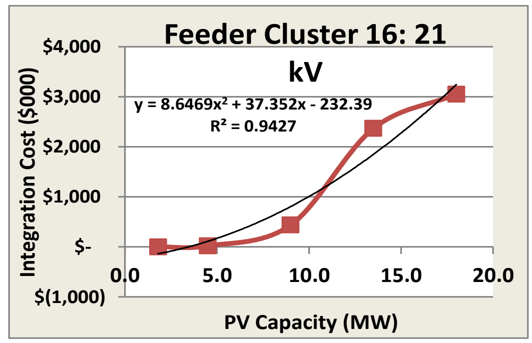


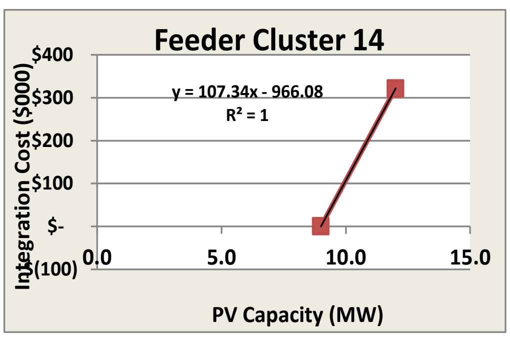


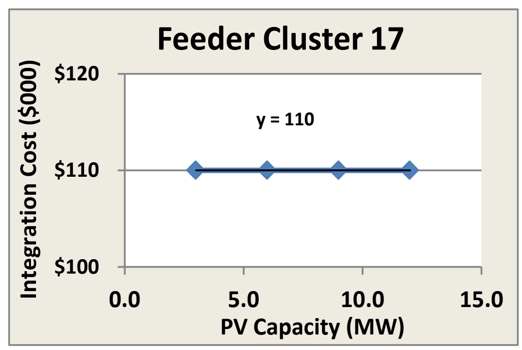

Feeder Cluster 12
$y = -201.03x^2 + 4896x - 22029$
$R^2 = 1$
Integration Cost ($000)
PV Capacity (MW)

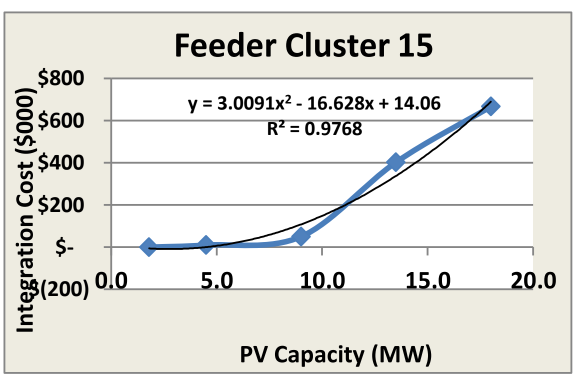

Feeder Cluster 16: 12kV
$y = 19.455x^2 + 56.028x - 232.39$
$R^2 = 0.9427$
Integration Cost ($000)
PV Capacity (MW)

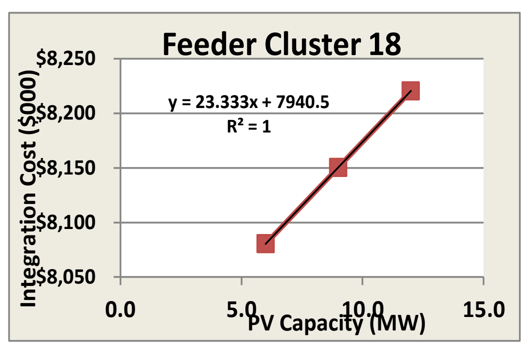

Feeder Cluster 13
$y = 16.288x^2 - 106.63x + 1297.6$
$R^2 = 0.9535$
Integration Cost ($000)
PV Capacity (MW)

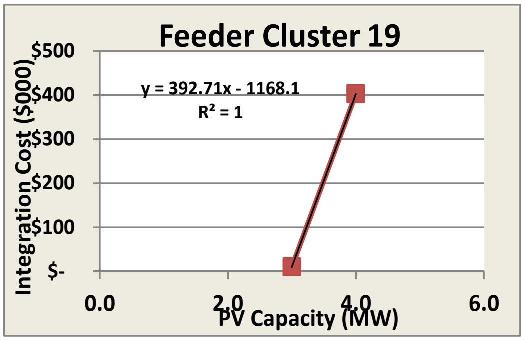

Feeder Cluster 16: 21 kV
$y = 8.6469x^2 + 37.352x - 232.39$
$R^2 = 0.9427$
Integration Cost ($000)
PV Capacity (MW)

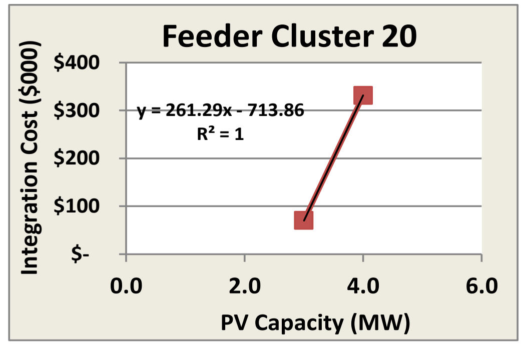

Feeder Cluster 14
$y = 107.34x - 966.08$
$R^2 = 1$
Integration Cost ($000)
PV Capacity (MW)


Feeder Cluster 17
y = 110
Integration Cost ($000)
PV Capacity (MW)


Feeder Cluster 15
$y = 3.0091x^2 - 16.628x + 14.06$
$R^2 = 0.9768$
Integration Cost ($000)
PV Capacity (MW)


Feeder Cluster 18
$y = 23.333x + 7940.5$
$R^2 = 1$
Integration Cost ($000)
PV Capacity (MW)





Notes:
Equations Only valid over range of data points
Omitted clusters have zero costs over full range

9. Appendix C: Transmission Upgrades

Low Retail DGPV Scenario

Year	Total PV Capacity (MW)			Transmission Cost ($ Millions)		
	Low Wholesale	Mid Wholesale	High Wholesale	Low Wholesale	Mid Wholesale	High Wholesale
2015	159	159	159	$0	$0	$0
2016	278	378	480	$0	$0	$0
2017	383	588	796	$0	$0	$0
2018	496	814	1,133	$0	$0	$0
2019	604	1,039	1,475	$0	$0	$9
2020	726	1,284	1,844	$0	$1	$24
2021	892	1,579	2,266	$0	$13	$42
2022	1,046	1,867	2,689	$0	$25	$61
2023	1,229	2,191	3,155	$0	$39	$82
2024	1,435	2,545	3,659	$7	$54	$107

Mid Retail DGPV Forecast

Year	Total PV Capacity (MW)			Transmission Cost ($ Millions)		
	Low Wholesale	Mid Wholesale	High Wholesale	Low Wholesale	Mid Wholesale	High Wholesale
2015	559	559	559	$0	$0	$0
2016	1,184	1,284	1,385	$0	$1	$5
2017	1,710	1,915	2,123	$18	$27	$36
2018	2,145	2,463	2,782	$37	$51	$65
2019	2,562	2,997	3,433	$55	$75	$96
2020	2,982	3,541	4,100	$74	$101	$129
2021	3,412	4,100	4,787	$95	$129	$164
2022	3,813	4,635	5,457	$114	$156	$201
2023	4,218	5,180	6,145	$135	$186	$241
2024	4,627	5,738	6,852	$156	$217	$284

High Retail DGPV Forecast

Year	Total PV Capacity (MW)			Transmission Cost ($ Millions)		
	Low Wholesale	Mid Wholesale	High Wholesale	Low Wholesale	Mid Wholesale	High Wholesale
2015	559	559	559	$0	$0	$0
2016	1,184	1,284	1,385	$0	$1	$5
2017	1,886	2,091	2,299	$26	$34	$43
2018	2,645	2,962	3,281	$59	$73	$88
2019	3,377	3,812	4,248	$93	$114	$136
2020	4,103	4,662	5,221	$129	$158	$188
2021	4,859	5,547	6,234	$168	$206	$246
2022	5,583	6,405	7,227	$208	$256	$307
2023	6,313	7,275	8,240	$251	$310	$374
2024	7,053	8,163	9,277	$296	$368	$446

10. Appendix D: Cost Benefit Summaries (Retail)

1) Distribution Costs and Benefits

Low-Retail, Low Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$1	$0	$1	$15	$9
2016	197	81	278	$3	$0	$3	$14	$8
2017	252	131	383	$4	$0	$4	$15	$9
2018	316	180	496	$9	$0	$8	$26	$15
2019	397	207	604	$10	$1	$9	$23	$13
2020	493	234	726	$12	$1	$11	$22	$12
2021	617	275	892	$14	$1	$13	$21	$12
2022	771	275	1,046	$19	$2	$17	$22	$13
2023	954	275	1,229	$24	$3	$20	$21	$12
2024	1,160	275	1,435	$30	$5	$26	$22	$13

Low-Retail, Mid Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$1	$0	$1	$15	$9
2016	197	181	378	$3	$0	$3	$16	$9
2017	252	336	588	$4	$0	$4	$14	$8
2018	316	498	814	$9	$0	$9	$28	$16
2019	397	642	1,039	$11	$1	$10	$25	$14
2020	493	792	1,284	$13	$1	$12	$24	$14
2021	617	962	1,579	$16	$2	$14	$23	$13
2022	771	1,096	1,867	$22	$2	$19	$25	$14
2023	954	1,237	2,191	$27	$4	$23	$24	$14
2024	1,160	1,385	2,545	$37	$6	$31	$27	$15

Low-Retail, High Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$1	$0	$1	$15	$9
2016	197	283	480	$3	$0	$3	$16	$9
2017	252	545	796	$4	$0	$4	$17	$10
2018	316	817	1,133	$10	$0	$10	$30	$17
2019	397	1,078	1,475	$12	$1	$11	$28	$16
2020	493	1,351	1,844	$14	$1	$13	$27	$15
2021	617	1,649	2,266	$20	$2	$17	$28	$16
2022	771	1,918	2,689	$26	$3	$23	$30	$17
2023	954	2,201	3,155	$31	$5	$27	$28	$16
2024	1,160	2,499	3,659	$41	$7	$34	$29	$17

Mid Retail, Low Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$7	$0	$7	$14	$8
2016	1,103	81	1,184	$11	$0	$10	$9	$5
2017	1,578	131	1,710	$21	$1	$20	$13	$7
2018	1,965	180	2,145	$28	$1	$26	$13	$8
2019	2,355	207	2,562	$43	$4	$39	$16	$9
2020	2,749	234	2,982	$53	$7	$46	$17	$10
2021	3,138	275	3,412	$68	$10	$58	$18	$10
2022	3,538	275	3,813	$81	$15	$67	$19	$11
2023	3,943	275	4,218	$97	$22	$75	$19	$11
2024	4,353	275	4,627	$107	$31	$76	$18	$10

Mid Retail, Mid Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$7	$0	$7	$14	$8
2016	1,103	181	1,284	$12	$0	$11	$10	$6
2017	1,578	336	1,915	$22	$1	$21	$13	$8
2018	1,965	498	2,463	$28	$2	$27	$14	$8
2019	2,355	642	2,997	$45	$4	$41	$17	$10
2020	2,749	792	3,541	$58	$8	$51	$18	$11
2021	3,138	962	4,100	$74	$11	$63	$20	$11
2022	3,538	1,096	4,635	$90	$15	$76	$21	$12
2023	3,943	1,237	5,180	$109	$22	$87	$22	$13
2024	4,353	1,385	5,738	$125	$30	$95	$22	$13

Mid Retail, High Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$7	$0	$7	$14	$8
2016	1,103	283	1,385	$12	$0	$12	$11	$6
2017	1,578	545	2,123	$23	$1	$22	$14	$8
2018	1,965	817	2,782	$32	$2	$30	$15	$9
2019	2,355	1,078	3,433	$52	$4	$48	$20	$12
2020	2,749	1,351	4,100	$70	$7	$63	$23	$13
2021	3,138	1,649	4,787	$90	$11	$80	$25	$14
2022	3,538	1,918	5,457	$115	$15	$100	$28	$16
2023	3,943	2,201	6,145	$134	$22	$112	$28	$16
2024	4,353	2,499	6,852	$151	$29	$122	$28	$16

High-Retail, Low Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$8	$0	$8	$16	$9
2016	1,103	81	1,184	$13	$0	$13	$12	$7
2017	1,755	131	1,886	$30	$1	$29	$16	$9
2018	2,464	180	2,645	$51	$2	$49	$20	$11
2019	3,170	207	3,377	$69	$5	$64	$20	$12
2020	3,870	234	4,103	$83	$9	$74	$19	$11
2021	4,585	275	4,859	$127	$13	$114	$25	$14
2022	5,308	275	5,583	$162	$19	$143	$27	$15
2023	6,038	275	6,313	$210	$29	$181	$30	$17
2024	6,778	275	7,053	$285	$42	$243	$36	$20

High-Retail, Mid Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$8	$0	$8	$16	$9
2016	1,103	181	1,284	$14	$0	$14	$13	$7
2017	1,755	336	2,091	$31	$1	$30	$17	$10
2018	2,464	498	2,962	$53	$2	$51	$21	$12
2019	3,170	642	3,812	$74	$5	$69	$22	$12
2020	3,870	792	4,662	$89	$9	$79	$20	$12
2021	4,585	962	5,547	$137	$14	$123	$27	$15
2022	5,308	1,096	6,405	$174	$20	$155	$29	$17
2023	6,038	1,237	7,275	$227	$29	$198	$33	$19
2024	6,778	1,385	8,163	$309	$41	$268	$40	$23

High-Retail, High Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$8	$0	$8	$16	$9
2016	1,103	283	1,385	$15	$0	$15	$14	$8
2017	1,755	545	2,299	$32	$1	$31	$18	$10
2018	2,464	817	3,281	$57	$2	$55	$22	$13
2019	3,170	1,078	4,248	$82	$5	$77	$24	$14
2020	3,870	1,351	5,221	$104	$9	$94	$24	$14
2021	4,585	1,649	6,234	$157	$14	$143	$31	$18
2022	5,308	1,918	7,227	$205	$20	$185	$35	$20
2023	6,038	2,201	8,240	$266	$29	$236	$39	$22
2024	6,778	2,499	9,277	$353	$41	$313	$46	$26

2) Transmission Costs and Benefits

Low-Retail, Low Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$0	$0	($0)	($1)	($0)
2016	197	81	278	$0	$0	($0)	($1)	($1)
2017	252	131	383	$0	$0	($0)	($1)	($1)
2018	316	180	496	$0	$0	($0)	($1)	($1)
2019	397	207	604	$0	$0	($0)	($1)	($1)
2020	493	234	726	$0	$1	($1)	($1)	($1)
2021	617	275	892	$0	$1	($1)	($1)	($1)
2022	771	275	1,046	$0	$1	($1)	($1)	($1)
2023	954	275	1,229	$0	$2	($2)	($2)	($1)
2024	1,160	275	1,435	$6	$2	$4	$3	$2

Low-Retail, Mid Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$0	$0	($0)	($1)	($0)
2016	197	181	378	$0	$0	($0)	($1)	($0)
2017	252	336	588	$0	$0	($0)	($1)	($0)
2018	316	498	814	$0	$0	($0)	($1)	($0)
2019	397	642	1,039	$0	$0	($0)	($1)	($0)
2020	493	792	1,284	$0	$0	$0	$0	$0
2021	617	962	1,579	$5	$0	$5	$7	$4
2022	771	1,096	1,867	$10	$1	$10	$13	$7
2023	954	1,237	2,191	$17	$1	$16	$17	$10
2024	1,160	1,385	2,545	$25	$1	$24	$20	$12

Low-Retail, High Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Vb	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$0	$0	($0)	($1)	($0)
2016	197	283	480	$0	$0	($0)	($1)	($0)
2017	252	545	796	$0	$0	($0)	($0)	($0)
2018	316	817	1,133	$0	$0	($0)	($0)	($0)
2019	397	1,078	1,475	$2	$0	$2	$5	$3
2020	493	1,351	1,844	$6	$0	$6	$12	$7
2021	617	1,649	2,266	$11	$0	$11	$18	$10
2022	771	1,918	2,689	$17	$0	$17	$22	$13
2023	954	2,201	3,155	$25	$1	$24	$25	$15
2024	1,160	2,499	3,659	$34	$1	$33	$28	$16

Mid Retail, Low Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	81	1,184	$0	$1	($1)	($1)	($1)
2017	1,578	131	1,710	$17	$2	$15	$9	$5
2018	1,965	180	2,145	$34	$3	$31	$16	$9
2019	2,355	207	2,562	$51	$4	$47	$20	$11
2020	2,749	234	2,982	$68	$5	$64	$23	$13
2021	3,138	275	3,412	$87	$6	$81	$26	$15
2022	3,538	275	3,813	$106	$7	$99	$28	$16
2023	3,943	275	4,218	$126	$8	$118	$30	$17
2024	4,353	275	4,627	$147	$9	$137	$32	$18

Mid Retail, Mid Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	181	1,284	$1	$1	($0)	($0)	($0)
2017	1,578	336	1,915	$22	$2	$20	$13	$7
2018	1,965	498	2,463	$40	$2	$38	$19	$11
2019	2,355	642	2,997	$59	$3	$56	$24	$14
2020	2,749	792	3,541	$78	$4	$74	$27	$15
2021	3,138	962	4,100	$98	$5	$94	$30	$17
2022	3,538	1,096	4,635	$119	$5	$114	$32	$18
2023	3,943	1,237	5,180	$141	$6	$135	$34	$20
2024	4,353	1,385	5,738	$165	$7	$157	$36	$21

Mid Retail, High Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	283	1,385	$4	$1	$3	$3	$1
2017	1,578	545	2,123	$27	$2	$25	$16	$9
2018	1,965	817	2,782	$46	$2	$44	$22	$13
2019	2,355	1,078	3,433	$66	$3	$63	$27	$15
2020	2,749	1,351	4,100	$86	$3	$83	$30	$17
2021	3,138	1,649	4,787	$108	$4	$104	$33	$19
2022	3,538	1,918	5,457	$131	$5	$126	$36	$20
2023	3,943	2,201	6,145	$155	$5	$149	$38	$22
2024	4,353	2,499	6,852	$180	$6	$174	$40	$23

High-Retail, Low Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	81	1,184	$0	$1	($1)	($1)	($1)
2017	1,755	131	1,886	$24	$2	$21	$12	$7
2018	2,464	180	2,645	$55	$4	$51	$21	$12
2019	3,170	207	3,377	$87	$5	$82	$26	$15
2020	3,870	234	4,103	$121	$7	$115	$30	$17
2021	4,585	275	4,859	$159	$8	$151	$33	$19
2022	5,308	275	5,583	$198	$10	$188	$35	$20
2023	6,038	275	6,313	$240	$12	$228	$38	$22
2024	6,778	275	7,053	$285	$15	$270	$40	$23

High-Retail, Mid Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	181	1,284	$1	$1	($0)	($0)	($0)
2017	1,755	336	2,091	$29	$2	$27	$15	$9
2018	2,464	498	2,962	$61	$3	$58	$23	$13
2019	3,170	642	3,812	$95	$4	$90	$29	$16
2020	3,870	792	4,662	$131	$6	$125	$32	$18
2021	4,585	962	5,547	$171	$7	$163	$36	$20
2022	5,308	1,096	6,405	$213	$9	$204	$38	$22
2023	6,038	1,237	7,275	$258	$10	$247	$41	$23
2024	6,778	1,385	8,163	$306	$13	$293	$43	$25

High-Retail, High Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$0	$1	($1)	($1)	($1)
2016	1,103	283	1,385	$4	$1	$3	$3	$1
2017	1,755	545	2,299	$33	$2	$31	$18	$10
2018	2,464	817	3,281	$66	$3	$63	$26	$15
2019	3,170	1,078	4,248	$102	$4	$98	$31	$18
2020	3,870	1,351	5,221	$139	$5	$134	$35	$20
2021	4,585	1,649	6,234	$181	$6	$175	$38	$22
2022	5,308	1,918	7,227	$226	$8	$218	$41	$23
2023	6,038	2,201	8,240	$274	$9	$265	$44	$25
2024	6,778	2,499	9,277	$326	$11	$314	$46	$26

3) Total Net Value

Low-Retail, Low Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$1	$0	$1	$14	$8
2016	197	81	278	$3	$0	$3	$13	$7
2017	252	131	383	$4	$0	$4	$14	$8
2018	316	180	496	$9	$1	$8	$25	$14
2019	397	207	604	$10	$1	$9	$22	$13
2020	493	234	726	$12	$2	$10	$21	$12
2021	617	275	892	$14	$2	$12	$20	$11
2022	771	275	1,046	$19	$3	$16	$21	$12
2023	954	275	1,229	$24	$5	$19	$20	$11
2024	1,160	275	1,435	$36	$7	$29	$25	$14

Low-Retail, Mid Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$1	$0	$1	$14	$8
2016	197	181	378	$3	$0	$3	$15	$8
2017	252	336	588	$4	$0	$3	$14	$8
2018	316	498	814	$9	$0	$9	$27	$15
2019	397	642	1,039	$11	$1	$10	$24	$14
2020	493	792	1,284	$14	$2	$12	$24	$14
2021	617	962	1,579	$21	$2	$19	$31	$17
2022	771	1,096	1,867	$32	$3	$29	$38	$22
2023	954	1,237	2,191	$44	$5	$39	$41	$23
2024	1,160	1,385	2,545	$62	$7	$55	$47	$27

Low-Retail, High Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	88	71	159	$1	$0	$1	$14	$8
2016	197	283	480	$3	$0	$3	$15	$9
2017	252	545	796	$4	$0	$4	$16	$9
2018	316	817	1,133	$10	$1	$9	$30	$17
2019	397	1,078	1,475	$14	$1	$13	$33	$19
2020	493	1,351	1,844	$21	$2	$19	$39	$22
2021	617	1,649	2,266	$31	$2	$29	$46	$26
2022	771	1,918	2,689	$43	$3	$40	$52	$29
2023	954	2,201	3,155	$56	$5	$51	$53	$30
2024	1,160	2,499	3,659	$75	$7	$67	$58	$33

Mid Retail, Low Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$7	$1	$6	$13	$7
2016	1,103	81	1,184	$11	$2	$9	$8	$5
2017	1,578	131	1,710	$38	$3	$35	$22	$13
2018	1,965	180	2,145	$61	$4	$57	$29	$17
2019	2,355	207	2,562	$93	$8	$86	$36	$21
2020	2,749	234	2,982	$122	$12	$110	$40	$23
2021	3,138	275	3,412	$155	$16	$139	$44	$25
2022	3,538	275	3,813	$187	$21	$166	$47	$27
2023	3,943	275	4,218	$223	$30	$193	$49	$28
2024	4,353	275	4,627	$254	$40	$214	$49	$28

Mid Retail, Mid Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$7	$1	$6	$13	$7
2016	1,103	181	1,284	$13	$2	$11	$10	$6
2017	1,578	336	1,915	$44	$3	$41	$26	$15
2018	1,965	498	2,463	$69	$4	$65	$33	$19
2019	2,355	642	2,997	$104	$7	$97	$41	$23
2020	2,749	792	3,541	$136	$11	$125	$45	$26
2021	3,138	962	4,100	$172	$15	$157	$50	$29
2022	3,538	1,096	4,635	$210	$20	$190	$54	$31
2023	3,943	1,237	5,180	$250	$28	$222	$56	$32
2024	4,353	1,385	5,738	$290	$37	$253	$58	$33

Mid Retail, High Wholesale DGPV Scenario

	DGPV Capacity (MW)			Net Cost ($ Millions)				
Year	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$7	$1	$6	$13	$7
2016	1,103	283	1,385	$16	$1	$15	$13	$8
2017	1,578	545	2,123	$50	$3	$47	$30	$17
2018	1,965	817	2,782	$78	$4	$74	$38	$22
2019	2,355	1,078	3,433	$118	$7	$111	$47	$27
2020	2,749	1,351	4,100	$156	$11	$146	$53	$30
2021	3,138	1,649	4,787	$198	$15	$184	$59	$33
2022	3,538	1,918	5,457	$245	$19	$226	$64	$36
2023	3,943	2,201	6,145	$289	$27	$262	$66	$38
2024	4,353	2,499	6,852	$332	$35	$296	$68	$39

High-Retail, Low Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$8	$1	$7	$15	$9
2016	1,103	81	1,184	$13	$2	$12	$11	$6
2017	1,755	131	1,886	$53	$3	$50	$29	$16
2018	2,464	180	2,645	$106	$5	$100	$41	$23
2019	3,170	207	3,377	$156	$10	$146	$46	$26
2020	3,870	234	4,103	$204	$15	$189	$49	$28
2021	4,585	275	4,859	$286	$21	$265	$58	$33
2022	5,308	275	5,583	$360	$29	$331	$62	$36
2023	6,038	275	6,313	$450	$41	$409	$68	$39
2024	6,778	275	7,053	$569	$56	$513	$76	$43

High-Retail, Mid Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$8	$1	$7	$15	$9
2016	1,103	181	1,284	$15	$2	$14	$13	$7
2017	1,755	336	2,091	$60	$3	$57	$32	$18
2018	2,464	498	2,962	$114	$5	$109	$44	$25
2019	3,170	642	3,812	$169	$10	$159	$50	$29
2020	3,870	792	4,662	$220	$15	$204	$53	$30
2021	4,585	962	5,547	$307	$21	$287	$62	$36
2022	5,308	1,096	6,405	$387	$28	$359	$68	$39
2023	6,038	1,237	7,275	$485	$40	$445	$74	$42
2024	6,778	1,385	8,163	$615	$54	$562	$83	$47

High-Retail, High Wholesale DGPV Scenario

Year	DGPV Capacity (MW)			Net Cost ($ Millions)				
	Retail	Wholesale	Total	Costs	Benefits	Net	($/kW)	($/MWh)
2015	488	71	559	$8	$1	$7	$15	$9
2016	1,103	283	1,385	$19	$1	$18	$16	$9
2017	1,755	545	2,299	$66	$3	$63	$36	$20
2018	2,464	817	3,281	$123	$5	$118	$48	$27
2019	3,170	1,078	4,248	$184	$9	$175	$55	$31
2020	3,870	1,351	5,221	$243	$14	$229	$59	$34
2021	4,585	1,649	6,234	$338	$20	$318	$69	$40
2022	5,308	1,918	7,227	$431	$28	$403	$76	$43
2023	6,038	2,201	8,240	$539	$39	$501	$83	$47
2024	6,778	2,499	9,277	$679	$52	$627	$93	$53

Appendix B: Navigant Distributed Solar Market Assessment Study

NAVIGANT

NEM 2.0 and Distributed Solar Market Assessment Study

Prepared for:
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Reference No.: 173530
August, 2015

Executive Summary

With the passage of AB 327, the legislature has asked the California Public Utilities Commission (CPUC) to perform a balancing act that supports a growing sustainable market for renewable distributed generation (DG) solar energy in California while minimizing the cost impacts associated with current Net Energy Metering (NEM) policies.[1]

Navigant's NEM 2.0 Distributed Solar Market Assessment Study is largely driven by the need to analyze whether the distributed solar photovoltaic (PV) market in California will continue to grow sustainably under different rate reform and NEM 2.0 scenarios, as required by Assembly Bill 327 (AB 327).[2]

In the context of AB 327, to fully assess whether the distributed solar market in California is sustainable, it is important to understand the health of the third party owned (TPO) business model by estimating current and future margins of TPO third party owners of distributed solar in California. Navigant proposes that the assessment of market sustainability should be measured in the following ways:

1. Understanding the current and future DG solar PV system costs.
2. Understanding current costs, prices, and margins (or returns) of TPOs and equity providers (TPO/Equity providers) in California as compared with other states.
3. Estimating future returns to TPO/Equity providers under the proposed NEM/rate reform scenarios to ensure market viability in PG&E's service territory.

1.1 *Distributed PV System Cost Build-up and Forecast*

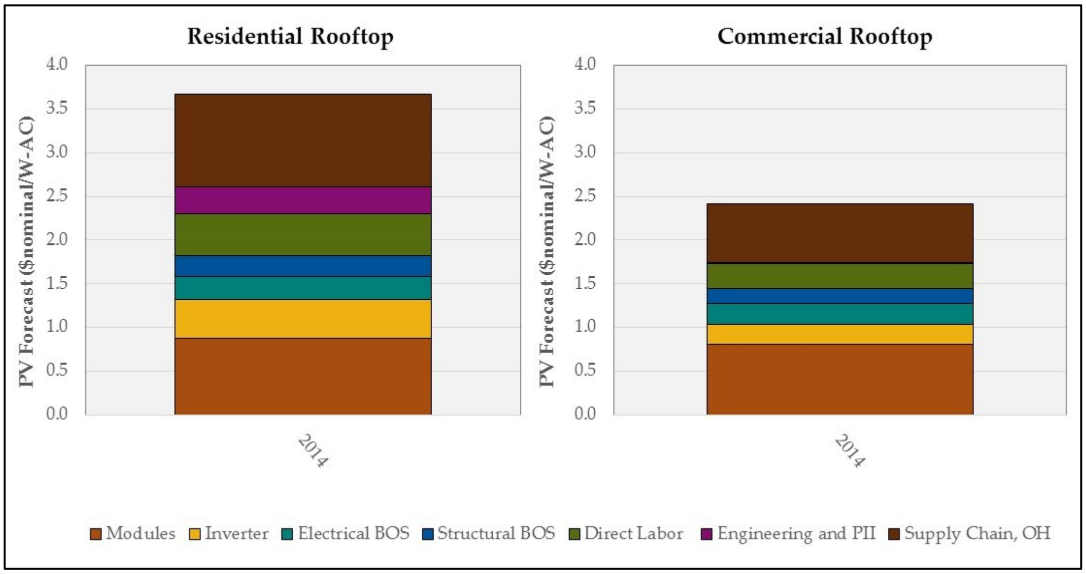
1.1.1 PV System Costs – Bottom-Up Cost Analysis 2014

Navigant developed a detailed cost analysis for commercial solar PV systems based on a 250 kW system size and a residential system size of 5 kW. As displayed in Figure 1, Navigant's bottom-up estimate for installed PV system costs in 2014 are $3.67/W-AC ($3.12/Watt-DC) and $2.41/W-AC ($2.05/W-DC) for the residential and commercial sectors, respectively.

[1] www.cpuc.ca.gov/NR/rdonlyres/3E3E5309-90BC-4D98-B412-209255D67D66/0/August_Public_Tool_Workshop_Slides.pdf

[2] Bill Text - AB-327 Electricity: natural gas: rates: net energy metering:
http://leginfo.legislature.ca.gov/faces/billCompareClient.xhtml

Figure 1. Residential and Commercial Rooftop Installed System Costs, 2014

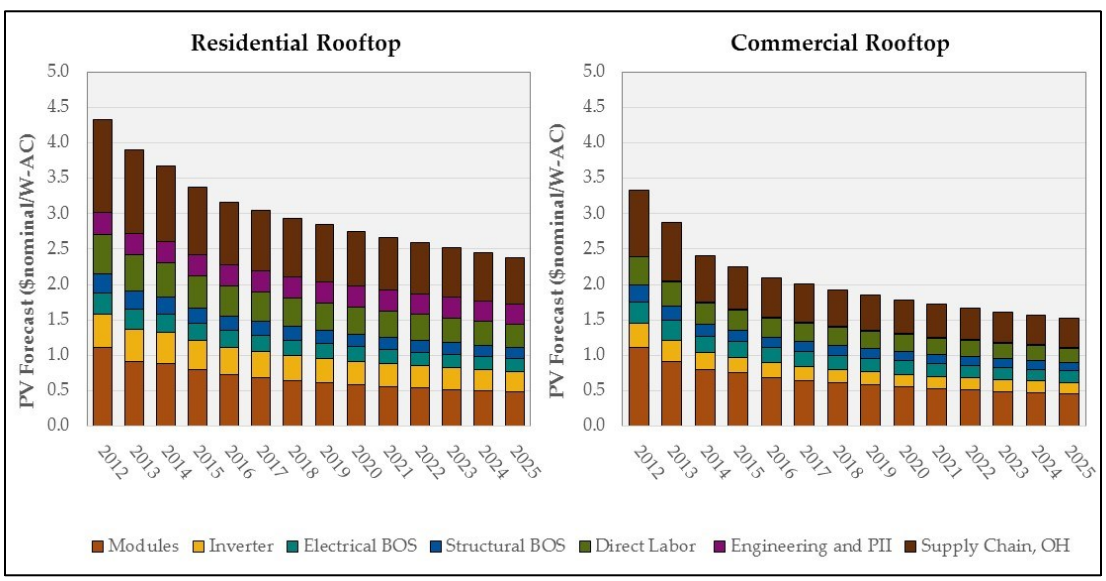


Source: Navigant analysis, 2015

1.1.2 PV System Cost Forecast through 2025

Figure 2 shows the estimated average cost forecast (mid-cost scenario) based on residential and commercial rooftop cost components between 2012 and 2025. Financing costs such as cost of debt and cost of equity are not included here but are factored into our analysis of levelized cost of energy (LCOE).

Figure 2. Residential and Commercial Rooftop Installed System Costs, 2012-2025 (Mid-Cost)

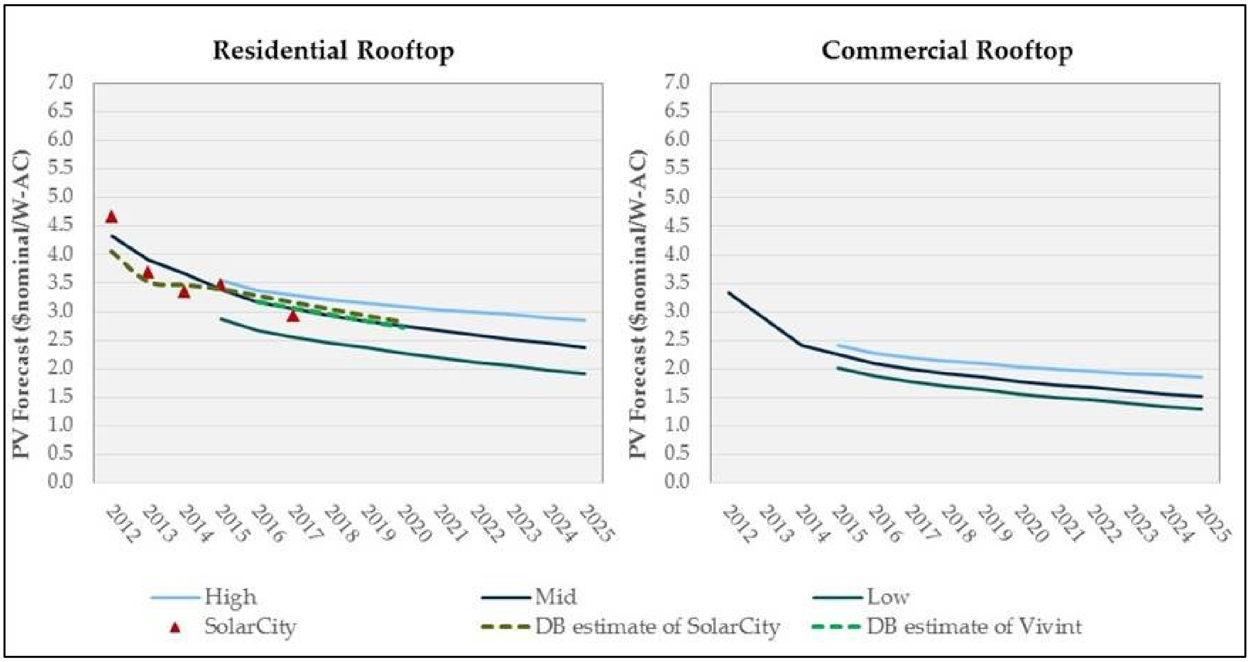


Source: Navigant analysis, 2015

In addition to the mid-cost forecast scenario above, Navigant developed low- and high-cost scenarios for the purpose of conducting sensitivity analysis.

Figure 3 illustrates the range in installed system costs for all three scenarios. Compared to the mid-cost scenario estimate, Navigant estimates a range of about +/- 20% for low and high costs throughout the forecast period in the residential and commercial sectors. We also present total system cost estimates from Deutsche Bank for SolarCity and Vivint in the residential sector for comparison.[3,4]

Figure 3. Residential and Commercial Rooftop Installed System Costs, 2012-2025 (Mid, High, Low)



Sources: Navigant forecast 2015, Deutsche Bank 2015, SolarCity Q1 2015

1.2 *Margin Analysis for Solar TPO/Equity Providers*

1.2.1 Understanding Margin in the Context of this Study

The purpose of this analysis is to estimate current margins as an indicator of expected TPO/Equity provider viability due to forecasted technology, business, market, and policy factors. Margin is a useful measure of TPO/Equity provider profitability due to its simple formulation and ubiquitous use and will inevitably vary across TPO/Equity providers based on factors specific to each company, their business model and strategy, and operational efficiencies. The analysis does not estimate actual margins of TPO/Equity providers in the accounting sense.[5] Rather, in this analysis, a discounted cash flow (DCF) and LCOE approach is used to estimate the investor's return, which approximates the margins that could be reasonably expected by TPO/Equity providers. Navigant's pro-forma model is applied in the

[3] "Heading West, Testing Commercial", Deutsche Bank, May 2015.

[4] "As Rates Flatten, California TAM Expands", Deutsche Bank, May 2015.

[5] Margin is usually referred to in the accounting sense, where it is defined as the profit expressed as a percentage of sales revenue.

reverse context to estimate TPO/Equity provider return. In other words, we apply the observed TPO PPA prices as the LCOE in order to calculate the corresponding TPO/Equity provider's return. The terms margin and return are used interchangeably as an indicator of TPO/Equity investor profitability. This analysis does not differentiate estimated returns into that made by a TPO provider versus equity investors; margin is lumped into a single value attributed to both TPO/Equity providers.

1.2.2 Survey of Residential PPA Rates in 2014

Navigant's research indicates that third party providers primarily choose to operate in jurisdictions where they can undercut utility offset rates and achieve profitability. Further, Navigant's research indicates that TPO pricing strategy is such that jurisdictions with higher offset rates are likely to see higher TPO PPA prices without direct cost-causation.

Navigant conducted a series of interviews with a number of leading national TPO solar PV service providers in the fourth quarter of 2014. These interviews provided corroborating evidence of the current state of TPO pricing strategies and margins in different regions of the United States. Through the interviews, Navigant obtained residential solar PPA price quotes from leading TPO providers for states with high penetration of distributed solar PV. TPO providers reported that their residential PPA rates are typically "at least 5%–20% below residential retail rates." Table 1 compares the quoted residential PPA prices with the average retail electricity rates in those states, according to data from the U.S. Energy Information Administration (EIA).

Consistent with the findings from the 2014 LBNL Tracking the Sun report, Navigant found that TPO vendors pursue value-based pricing strategies by undercutting the utility rate, which is evidenced by the positive correlation of pricing and the rate.[6] Customers who adopt solar tend to be high energy usage customers and, consequently, their average rates are typically higher than the EIA statewide average electricity rates. To illustrate this, we've also listed the marginal, i.e. highest tier, rates for a representative utility in each state.

[6] "Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012", Lawrence Berkeley National Laboratory, 2013.

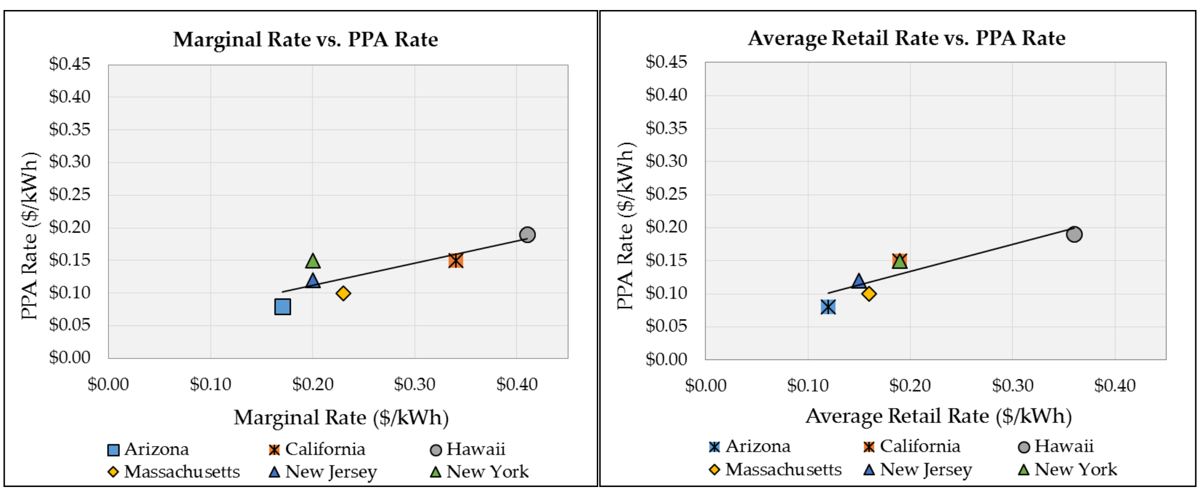
Table 1. Comparison of Reported Residential PPA Rates ($/kWh) in 2014

State	Quoted Residential PPA Rate[7]	Marginal, Highest Tier Electricity Rate	Average Retail Electricity Rate[8]
Arizona	$0.08	$0.17[9]	$0.12
California/PG&E	$0.15	$0.34[10]	$0.19[11]
Hawaii	$0.19	$0.41[12]	$0.36
Massachusetts	$0.10	$0.23[13]	$0.16
New Jersey	$0.12	$0.20[14]	$0.15
New York	$0.15	$0.20[15]	$0.19

Source: Navigant analysis, 2015

There is an observable correlation between high PPA rates and high electricity rates, which is more clearly displayed in Figure 4 (a graphical representation of the data in Table 1).

Figure 4. Comparison of Reported Residential PPA Rates ($/kWh) in 2014 by State



Source: Navigant analysis, 2015

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[7] Residential PPA rates quoted by leading TPO providers (with escalator tied to inflation, at 2-3% per year).

[8] EIA Average Retail Electricity Rates, October 2014.

[9] Arizona Public Service, Rate E-12. (www.aps.com/library/rates/e-12.pdf)

[10] Pacific Gas & Electric Company, Rate E-1, Zone X. (www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-1.pdf)

[11] PG&E October–December, 2014 Residential Retail Rates. (www.pge.com/tariffs/electric.shtml)

[12] Hawaiian Electric Company, Rate R. Includes Energy Cost Adjustment charge of $0.055210/kWh. (www.heco.com/vcmcontent/StaticFiles/FileScan/PDF/EnergyServices/Tarrifs/HECO/EFFRATESOCT2013.pdf)

[13] Eversource Energy, Rate R-1. (www.eversource.com/Content/docs/default-source/rates-tariffs/190.pdf?sfvrsn=6)

[14] Public Service Gas & Electric, Rate RS. (www.pseg.com/info/environment/ev/rlm-rs_rates.jsp)

[15] Consolidated Edison, Rate EL-1 and SC-1, Rate I. (https://apps1.coned.com/csol/msc_cc.asp, www.coned.com/documents/elecPSC10/SCs.pdf)

1.2.3 Comparison between California and Arizona

Table 2 presents a comparison of estimated pricing and margin in California compared with Arizona for 2012. The year 2012 was chosen as a study year because Navigant has reviewed the terms and conditions of a large number of TPO contracts in California for 2012.[16] Given the ramp down of the CSI contract database, more recent contracts from California were not readily available for analysis.

Table 2. Comparison of Pricing and Margin in Residential Sector for California and Arizona in 2012

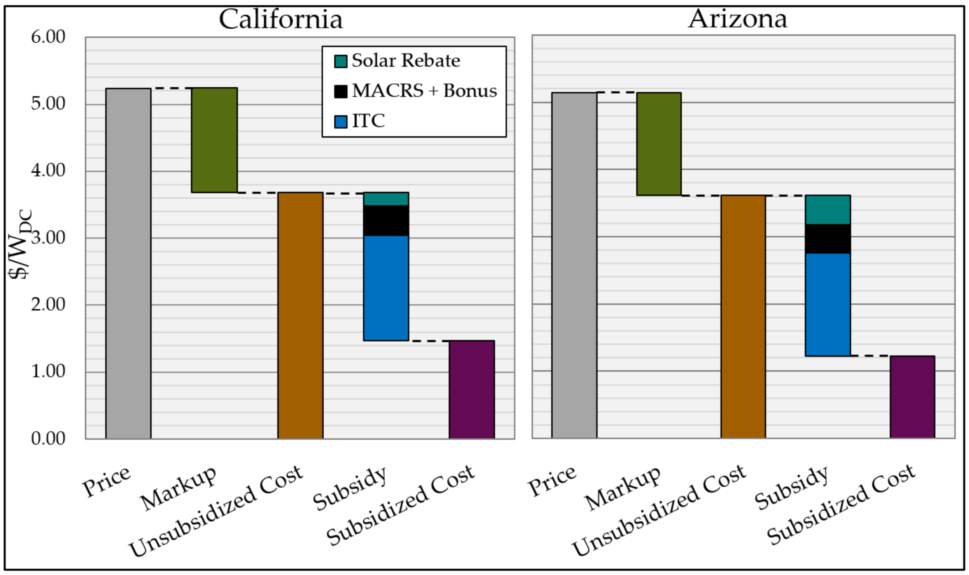
	California[17]	Arizona
2012 Average System Direct Sales Prices ($/$W_{DC}$)	$5.24[18]	$5.00-5.30[19]
2012 Estimated Average System Costs ($/$W_{DC}$) - **Unsubsidized**	$3.68	$3.80-$4.00
2012 Federal Tax Credit – 30% ITC ($/$W_{DC}$)	$1.57	$1.50-$1.60
2012 MACRS + Bonus Depreciation ($$W_{DC}$)[20]	$0.44	$0.42
2012 Solar Rebate / Incentive ($/$W_{DC}$)[21]	$0.20	$0.44
2012 Estimated Average System Costs ($/$W_{DC}$) – **Subsidized**	$1.47	$1.16-$1.26
2012 Levelized Average TPO PPA/lease Prices ($/kWh)	$0.23[22]	$0.10-$0.13[23]
2012 Levelized Offset Rates ($/kWh)	$0.33[24]	$0.11-0.16[25]

The analysis summarized in the Table 2 shows that average prices for systems installed in 2012 are similar in California and Arizona. System prices are reflective of system costs from an installer's perspective plus additional markup (as described in the following paragraphs). Navigant's research also

[16] Third Party Owner (TPO) Market Impact Study, conducted on behalf of the CPUC, Navigant, 2014.
[17] California data in this table is specific to PG&E service territory.
[18] Observed average residential system sales prices based on a sample of residential host-owned systems installed in in PG&E's territory in 2012 (CSI PowerClerk data set [n=861]).
[19] Average residential system sales prices in Arizona are based on Navigant estimates derived from Navigant's proprietary market research, project experience and interviews with customers and TPO providers.
[20] Navigant's DCF analysis is used to calculate the levelized results including additional multi-year benefits such as MACRS depreciation. Depreciation benefits were estimated by taking the difference between the present value (assuming a 6.96% discount rate) of the MACRS benefit stream and a 12-year straight line depreciation (i.e. the depreciation schedule that would be used in the absence of a MACRS).
[21] Based on average solar rebates/incentives throughout 2012 in CA and AZ.
[22] Observed average residential levelized TPO prices in California in 2012 are based on a sample of residential TPO contracts of customers in PG&E's service territory that were analyzed by Navigant (n=53). PPA/lease rates were levelized to account for different escalation rates in the TPO contracts.
[23] Average TPO prices in Arizona were estimated based on Navigant's proprietary market research, project experience and interviews with customers and TPO providers.
[24] Navigant obtained nominal offset rates for 10 different customer usage deciles from PG&E. These offset rates were weighted by annual usage information for each decile to calculate a weighted-average offset rate and then levelized.
[25] Navigant estimates that the Arizona offset rates varied from $0.11/kWh to $0.16/kWh in 2012 depending on the utility.

indicates that the underlying cost structure for installed systems is also very similar between the two states, as shown in
Figure 5 and Figure 6. However, as displayed in Figure 7, the observed TPO PPA/lease prices in California were significantly higher than in Arizona, pointing to higher returns in California. The PPA/lease price estimates are based on interviews with leading industry players, primary and secondary market research, and a calibrated pro-forma LCOE financial model.[26]

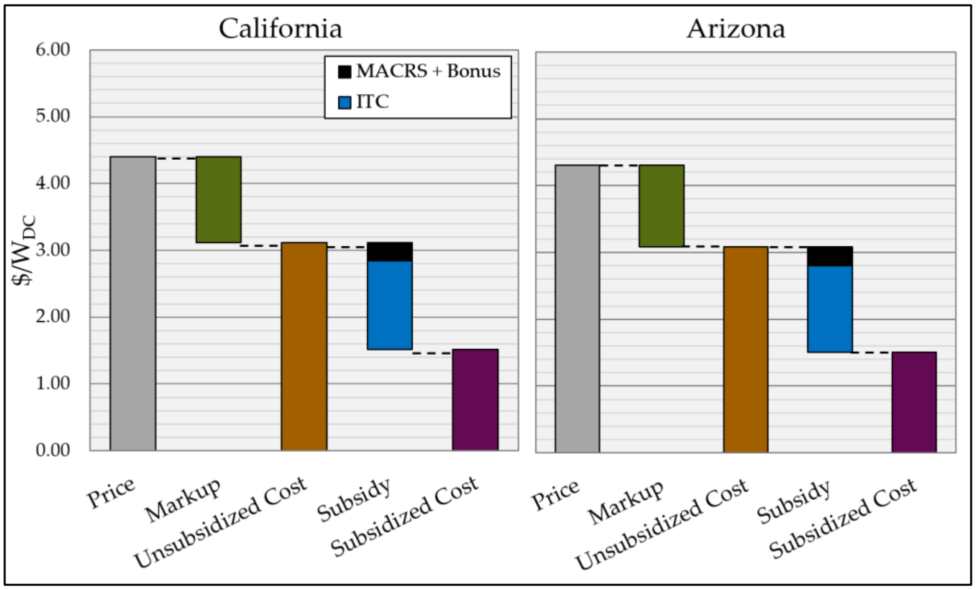
Figure 5. Impact of Subsidies on Cost of PV in Residential Sector for California and Arizona, 2012



Source: Navigant analysis, 2015

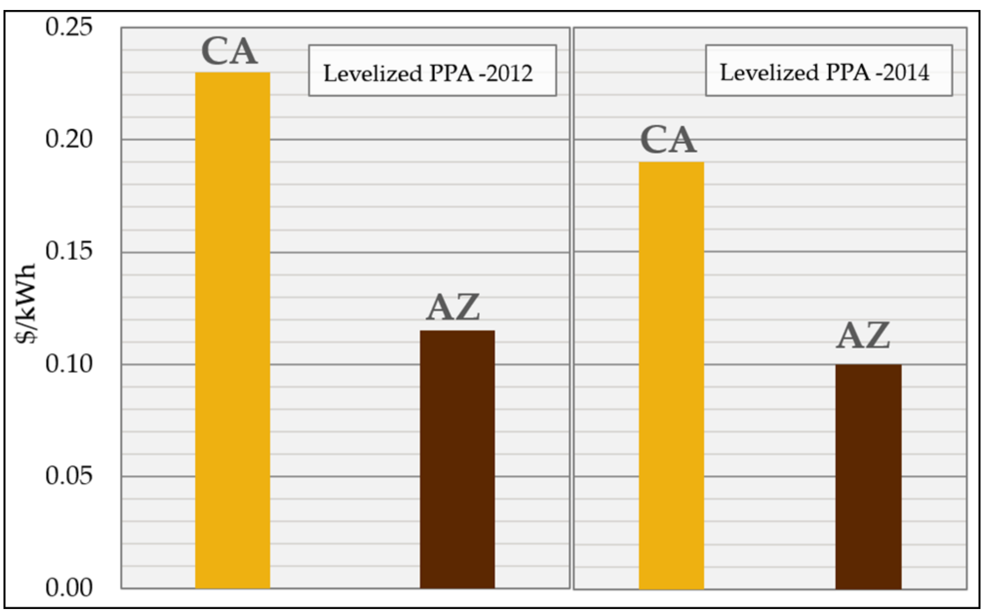
[26] Several leading residential installers provided TPO PPA/lease rates, which were converted into a levelized cost of electricity in order to make them comparable. In all cases the TPO rates were at least 5-20% below the utility's retail electricity rates in the first year.

Figure 6. Impact of Subsidies on Cost of PV in Residential Sector for California and Arizona, 2014



Source: Navigant analysis, 2015

Figure 7. Comparison of Residential PPA Prices for California and Arizona in 2012 and 2014



Source: Navigant analysis, 2015

Figure 5, Figure 6, and Figure 7 present a visual comparison of estimated pricing and margin in California compared with Arizona in 2012 and 2014. When reviewing the three figures above, note the following:

- **Price.** California data in these figures are specific to PG&E service territory. California 2012 price estimates are based on observed average residential system sales prices.[27] The California 2014 installed system price estimate is based on the bottom up cost estimate that was highlighted in the previous section plus markup (see below). Average residential installed prices in Arizona are based on Navigant estimates derived from Navigant's proprietary market research, project experience and interviews with customers and TPO providers.
- **Markup.** Navigant estimated system prices in 2014 assuming a 40% markup based on review of various third-party market reports, financial analyst estimates and market research.[28,29,30]
- **Unsubsidized costs.** Unsubsidized costs are simply price minus markup.
- **Subsidy.** Subsidies are calculated for both states and include solar rebates, ITC and accelerated depreciation (MACRS)[31] for 2012 and 2014. Solar rebates are based on average solar rebates/incentives in California and Arizona for 2012. The ITC subsidy assumes the Fair Market Value (FMV) is calculated using a cost method; therefore, the estimates presented on subsidized costs are viewed by Navigant to be conservative relative to an estimate of FMV based on the income method.
- **Subsidized cost.** Subsidized costs are a function of unsubsidized costs minus the subsidies in each state by year.
- **Levelized PPA.**[32] California 2012 levelized PPA prices are based on observed TPO contracts of customers in PG&E's service territory.[33] The remaining levelized PPA estimates are based on data received from interviews with leading industry players, primary and secondary market research and a calibrated pro-forma LCOE financial model. Several leading residential installers provided PPA rates, which were converted into a levelized PPA in order to make them comparable, i.e. taking into account different escalation rates.

1.2.4 Projected Margin of TPO/Equity Providers in PG&E's Service Territory

Research indicates that the relatively high residential retail rates in California, combined with the current NEM tariff structure, set the stage for pricing strategies that lead to the higher TPO/Equity provider returns in California as compared to other states. In the Navigant forecasts below, a **rate of return gradient** highlights the expected margins associated with a given first-year TPO rate (tied to an escalator) at any point in time. For instance, in Figure 8, we see that at $.10/kWh first-year PPA rate (tied

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[27] California 2012 price data derived from a sample of residential host-owned systems installed in PG&E's service territory in 2012 (CSI PowerClerk data set [n=861]).

[28] "As Rates Flatten, California TAM Expands", Deutsche Bank, May 2015.

[29] "Heading West, Testing Commercial", Deutsche Bank, May 2015.

[30] "U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices", National Renewable Energy Laboratory, October 2014.

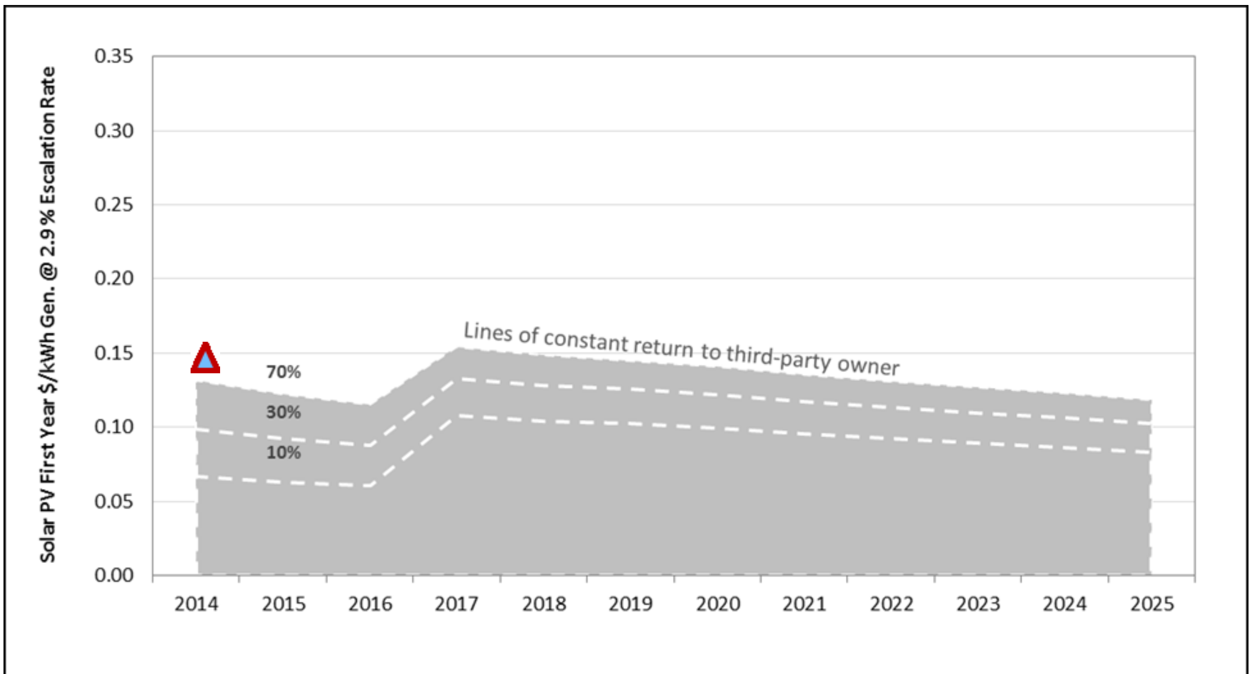
[31] Depreciation benefits were estimated by taking the difference between the present value (assuming a 6.96% discount rate) of the MACRS benefit stream and a 12-year straight line depreciation (i.e. the depreciation schedule that would be used in the absence of a MACRS).

[32] Levelized PPA prices are estimated by levelizing first-year PPA rates in California and Arizona assuming an escalation rate of 2.9% per year and a 6.96% discount rate.

[33] PG&E TPO 2012 contracts analyzed by Navigant (n=53).

to a 2.9% escalator) in 2014 would likely result in an estimated 30% return for the TPO/Equity provider. Similarly, we see that in order to maintain a 30% return, the TPO/Equity provider would need to set PPA prices at approximately $.14/kWh in 2017. In 2017, the first-year price for any given return increases as a result of the reduction of the federal ITC to 10%. Following 2017, the required price for a given return gradually declines due to forecasted decreases in the cost of solar PV technology and installation. In addition, a standard first-year PPA rate of $0.15 per kWh tied to a 2.9% escalator, reflective of a typical PPA in California[34] in 2014, would achieve an estimated return greater than 70% for the TPO/equity provider.

Figure 8. Residential Return Gradient (First-Year $/kWh Assuming a 2.9% Escalation Rate)

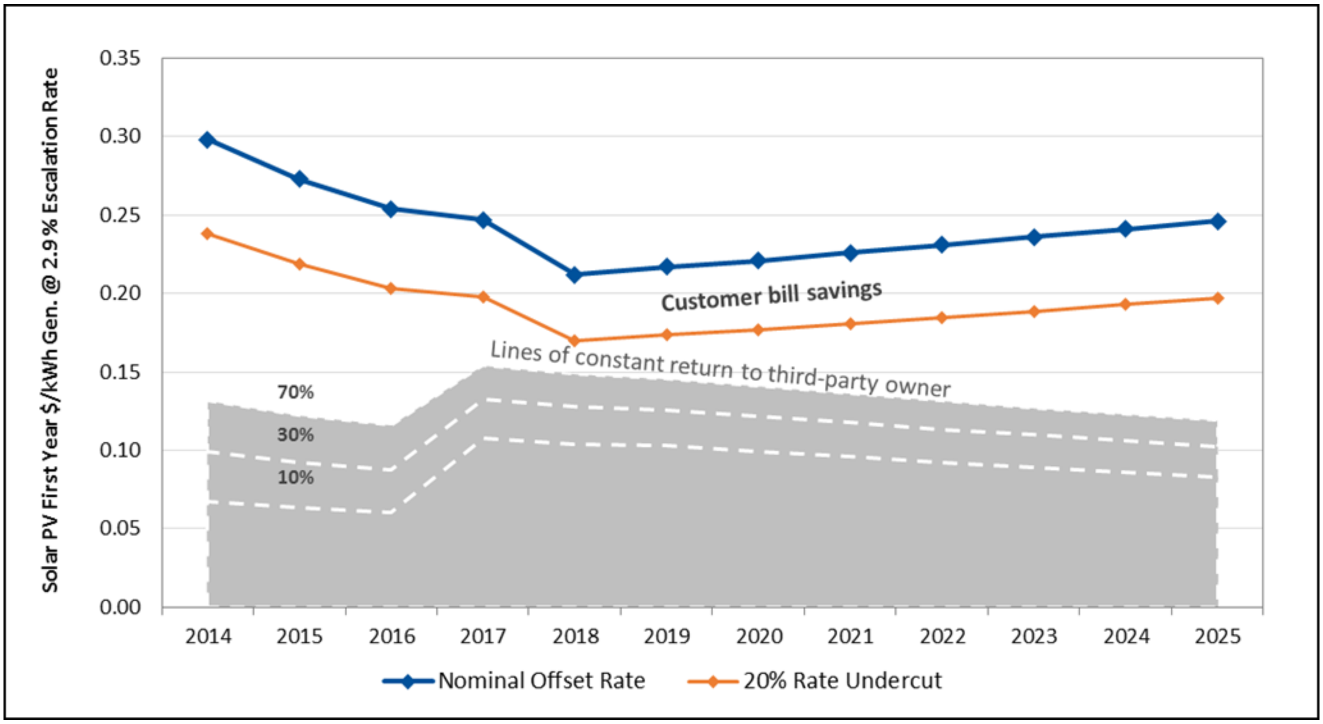


Typical first-year standard PPA rates in California

The above gradient can be used to compare a customer offset rate to various TPO price scenarios – assuming any illustrative TPO undercut strategy—and resulting TPO/Equity provider margins. The example shown in Figure 9 uses a 20% undercut strategy for an illustrative residential rate reform scenario. The difference between the offset rate and the 20% undercut is equivalent to customer savings from switching to solar PV. Even with the 20% rate undercut, in this scenario the TPO/Equity provider still has returns well over 70% (and hence, the ability to undercut rates further and offer even more attractive customer savings or adapt to policy changes while maintaining favorable levels of profitability).

[34] Based on a Power Purchase Agreement sample publicly available from SolarCity at: www.solarcity.com/sites/default/files/solarcity-contract-resi-ppa-example.pdf. The 2.9% escalator is an upper limit for both SolarCity and Sungevity (www.sungevity.com/faqs).

Figure 9. TPO 20% Undercut of Illustrative Residential Offset Rate



Source: Navigant analysis, 2015

1.3 *Key Findings TPO/Equity Provider Margin Analysis*

Key findings include the following:

- Navigant's research indicates that TPO providers primarily choose to operate in jurisdictions where they can undercut utility offset rates and achieve profitability.
- There is a positive correlation of the quoted 2014 power purchase agreement (PPA) pricing and the average and marginal retail rates in different states; only a small portion of the TPO price difference across different states can be attributed to installed system cost structure.
- Navigant's analysis of TPO data for California and Arizona shows that while the cost structure for installed PV systems are similar, observed PPA prices are significantly higher in California, which indicates higher margins for TPO/Equity providers in California.
- Navigant's research results indicate that there is substantial room for TPO providers to undercut the projected offset rates and still secure sufficient returns that will enable industry growth.